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Guidelines for NOx Control by Combustion Modification for Coal-Fired Utility Boilers Procedures for Reduction of NOx Emissions and Maximization of Boiler Efficiency

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16. ABSTRACT The report, which has been reviewed by industry experts, reflects the experience developed in successfully applying combustion modifications to reduce NOx emissions from coal-fired utility boilers. Although the report emphasizes coal-fired equipment, the same principles can be applied to gas- and oil-fired systems. Techniques, methods, and step-by-step procedures are detailed by example to guide utility personnel who may desire to conduct their own NOx emission reduction programs. Background information on operating parameters affecting NOx, necessary to understanding NOx emission control, is also included. Field studies were conducted from 1971 to 1979 to assess the feasibility of combustion modification to control NOx and other pollutants from large utility boilers. During these investigations, significant NOx reductions were demonstrated. For example, using a combination of staged combustion, low excess air firing, and other techniques reduced NOx by an average of 38%, over a range of 12 to 62%, in more than 35 utility boilers.

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Coal	Aerosols	Stationary Sources	21D	07D
Utilities	Slagging	Combustion Modification		13H
Boilers		Staged Firing	13A	
Combustion		Low Excess Air	21B	
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GUIDELINES FOR NO_x CONTROL BY COMBUSTION MODIFICATION FOR COAL-FIRED UTILITY BOILERS

Procedures for Reduction of NO_x Emissions and Maximization of Boiler Efficiency

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Guidelines Intended

— As a Reference for Combustion Modification Techniques and Procedures for NO_x Emission Control

— For Use by Utility Personnel in Designing Individual NO_x Reduction and Boiler Efficiency Optimization Programs

— For use by Boiler Manufacturers and Operators as a Guide and Supplement to Operating Procedures

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SECTION 1.0

INTRODUCTION

Combustion modifications for NO_x emission control were investigated and applied to utility boilers in California in the early 1960's. The techniques developed in these investigations concerned oil and gas fired boilers only, presumably because of the local need to control NO_x emissions in the Los Angeles area. Little if any further work was done until 1970 when field studies conducted under the sponsorship of the U.S. Environmental Protection Agency (EPA) commenced. Major emphasis of these studies concentrated on controlling emissions in pulverized coal-fired boilers.

More than 35 large, pulverized coal-fired utility boilers have been tested during the past 8 years in the EPA-sponsored field tests and the information developed can be combined with combustion modification test results obtained by other sources, such as, boiler operators and manufacturers, The Electric Power Research Institute (EPRI) and their contractors. One of the goals of the EPA-sponsored field tests was to establish whether combustion modifications can be used effectively for the control of NO_x emissions from coal fired utility boilers without incurring undesirable side effects.

Short term emission tests established a range of 20% to 60% reduction in NO_x emissions from pulverized coal fired utility boilers, with the average reduction being on the order of 35-40%. Other emissions did not increase as a result of the combustion modifications applied, nor were boiler efficiency, operability and safety adversely affected. The only remaining question is the long term effect on fireside tubewall slagging and corrosion when firing high sulfur and iron content bituminous coals. (EPA-sponsored field studies are in progress to provide an answer to this question.)

The purpose of this guideline is to compile the experience gained in the EPA-sponsored NO_x reduction tests and make it available to utility personnel who are required to reduce NO_x emissions and maximize efficiency in large utility boilers, especially those fired by pulverized coal. The objective is to present the combustion modification techniques and procedures, found to be successful in these investigations, in a readily understood form easily translatable into individual programs. The approach taken is that knowledge or understanding of NO_x combustion modification techniques and experience in planning test programs is lacking since utility personnel would not ordinarily be expected to plan test programs, stage firing patterns, bias mill output or operate routinely at low excess air levels. The assumption is made, however, that the responsible individual conducting the program possesses a practical understanding of combustion phenomena as related to utility boiler operation and a working knowledge of power plant combustion control systems. Although combustion techniques are different for low NO_x operation, the same general principles of boiler operation apply without violating normal good practice.

Operating variables and parameters which affect NO_x emissions and their interrelationship with steam temperature and automatic combustion controls are discussed to provide an insight into how to plan a test program, lower NO_x emissions, and translate these achievements into standard operating practices.

Test program planning is illustrated in the guidelines by examples encompassing investigation of major operating variables to determine the range of NO_x emission reduction possible for each combustion modification operating mode considered. Procedures for following the test plan are detailed in step-by-step progression leading to the determination of achievable NO_x emissions and operating configuration. Once this goal has been achieved, methods are suggested for translating the results into normal operating practice and for determining optimum boiler efficiency at reduced NO_x emitting conditions.

It is important that this entire guide be read and understood before attempting any boiler adjustments or modifications. In many cases it may be desirable to acquire the assistance of outside combustion control specialists, or to consult with the boiler manufacturer before proceeding with the NO_x emission reduction tests.

SECTION 2.0

BOILER INSPECTION AND MAINTENANCE

Financial requirements dictate that utility power plants operate as much as possible (normally 50 weeks per year) with a short annual outage (usually 2 weeks) for major repair requiring a shutdown and entry into the unit for cleaning, proper inspection, and maintenance to restore the boiler and turbine to original operating condition. Other opportunities do occur for minor repairs during forced outages but these are of short duration with little time for attention to other needed repairs. Consequently, boiler operating conditions are probably best immediately following the annual maintenance outage and deteriorate with continued operation to some level of less than optimum performance. Obviously it would be unrealistic to expect a boiler to be in prime condition throughout its yearly operating cycle. In pursuing a NO_x emission reduction program it should be recognized that ideal operating conditions may prevail for only a short period and that optimum NO_x emission levels may not always be achieved.

Before attempts are made to reduce NO_x emissions or to optimize efficiency on a boiler, it is wise to ascertain the operating condition of all components and, ideally, make corrections where necessary to assure maximum working capabilities. Where outages are not possible in order to effect the desired adjustments, recognition of these operating limitations should be noted for future correction and possible achievement of lower NO_x emissions. In the interim, critical boiler components should be inspected including automatic combustion controls, emission measurement instrumentation, fans, dampers, furnace and convection section surfaces, etc., with special attention given to the fuel burning equipment, i.e., pulverizers and burner registers, vanes and impellers. Experience has shown that one or two bad burners can severely limit the effective operation of a boiler, so a check of these critical components is important in fine tuning. A suggested inspection checklist follows. For a more complete list, boiler manufacturers recommendations should be consulted for specific type equipment in your plant. Ideally, these inspections should be made before initiating and periodically during the NO_x emission reduction program.

2.1 Furnace

- Inspect the burner throats for eyebrows or whisker accumulations of ash which might interfere with the complete and uniform combustion of the pulverized coal. Establish that burner throat surfaces are smooth providing no rough projections on which the slag may cling and build up.

- Ascertain that superheater and reheater tubes are clean with no fouling of flue gas passages to block and cause maldistribution of the gases resulting in higher stack temperatures.

- Make sure that furnace surfaces have no excessive deposits which might cause higher flame and gas temperatures resulting in high NO_x emissions and potential decreases in boiler efficiency.

- Inspect all soot and slag blowers making sure of their capability to remove slag and ash deposits so that higher gas temperatures can be avoided and efficiencies and NO_x emissions may be maintained at optimum values.

- Observation and furnace inspection doors should all be in operable condition. Clear visibility of burner throats, combustion conditions and furnace surfaces is important in assessing the effect of combustion modifications.

- On balanced draft boilers, it should be established that furnace casings are tight with minimal air infiltration especially in the burner area. Excessive hopper leakage on such units is also undesirable since it could interfere with and limit NO_x reduction techniques.

2.2 Air Heaters

- Air heater surfaces should be inspected for excessive fouling which could bottle up the furnace and interfere with the capability of the forced draft and induced draft fans in maintaining air and gas flow through the unit.

- Air heater blowers and water washing devices should also be maintained in operable condition to keep the air heaters in the best condition possible over the operating cycle of the unit.

- Air heater seals should be inspected and repaired or readjusted if there is excessive leakage in order to maintain full air flow delivery to the furnace at maximum load conditions.

2.3 Pulverizers

- Pulverizers should be inspected and adjusted for rated coal delivery to the furnace at the proper fineness (usually 70% through a 200 mesh screen). Excessively fine coal could prohibit rated fuel delivery while coarse coal would tend to have the opposite effect but result in more uneven distribution of fuel particles which could have an adverse effect on combustion. Also, coarse coal, as discussed in Section 3.7, could lower NO_x emissions but this effect would be minor.

- Experience shows that coal distribution between individual burner lines is notoriously uneven. Where maldistribution is excessive (which would be exhibited by rich combustion in some flames), steps should be taken to even out the distribution of coal between pipes. Remember that one bad burner can upset the entire combustion process.

- Check pulverizer feeder controls to minimize cycling of the coal feed. Otherwise, stack opacity limitations may be exceeded while operating under low NO_x conditions.

2.4 Combustion Controls

- Inspect and adjust all automatic combustion control instrumentation to respond smoothly to steam flow, steam pressure, and feedwater flow demands. Adjust master controllers and corresponding regulators freeing their operation so that hang-ups are minimized and jerky operation or "jumps" in combustion regulation do not occur. Reason: smooth regulation and safe control of combustion process is essential for optimum efficiency and NO_x emission control.

- Windbox dampers and forced draft and induced draft fan control dampers should be inspected for free operation. Play in damper linkage controls should be eliminated so that response is positive upon demand.

- Control pressure regulators should be inspected for proper operation to assure that output control pressures are sufficient to produce instant response at all firing rates.

- Normally automatic combustion controls are set up to anticipate load changes which are transmitted to the air controllers on load increases and to the fuel controllers on a decrease in load. Thus, more than sufficient air is supplied for combustion during load swings which can have an adverse effect on efficiency and NO_x emissions. On many control installations a wide safety margin is given to air "lead" over fuel and the automatic combustion control system on these installations should be readjusted to provide only the amount of "lead" necessary to follow load swings.

- Controls should also be adjusted to minimize effects of cycling or "hunting" above or below the control setpoint which makes it difficult to control NO_x emissions and can be wasteful of fuel.

2.5 Pulverized Coal Burners

Burner condition, without a doubt, is the single most important element in achieving NO_x emission reductions and optimizing combustion. Ideally coal and air flow should be uniform to each burner but in reality, this is seldom possible, especially in a pulverized coal installation. Coal distribution between burner pipes on a pulverizer is never uniform and the distribution can change with changes in load. Air distribution between burners, especially on utility boilers having a common windbox, is similarly non-uniform. This problem is compounded by inoperable or "sticking" burner registers or by burner register indicators which do not reflect the true percent opening of the registers or vanes. Thus, resistance to air flow through the burners can vary appreciably among burners and should be minimized for best results. Therefore, before a NO_x emission reduction program is begun, the following is recommended:

- Burner registers be inspected to ensure free operation, especially when the boiler is in operation and the register operators are hot and have the greatest tendency to bind.

- Make sure that burner register indicators reflect the true opening of the register. Goal: to be able to set all registers to the same percent open so that air flow may be as uniform as possible through the burners.

- Repeat the above for burner vanes even though the purpose of burner vanes normally is to direct the flow or rotation of air through the boiler (not regulation).

- Inspect all burner impellers (where they exist) for condition and coke deposits. Install new impellers where needed. Reason: non-symmetrical impellers or coke deposits can cause lopsided flames.

- Inspect the alloy tips or burner parts on the ends of pulverized coal burner pipes to make sure they have not burned off and are in good shape. Replace bad tips so that flame shape and symmetry will not interfere with uniform coal and air distribution at the burner.

2.6 Control Panel Instruments

Utility boilers are operated remotely from a central control room through means of the automatic combustion control system which selectively, at the operator's desire, provides for either automatic or hand control operation. Critical control instruments are strategically located in the control panel within sight and easy reach of the operator. Other instruments essential to defining complete operating conditions such as, temperature, pressure, and flow indicators and recorders, ammeters, O_2 meters, draft gauges, damper position indicators, etc., are also grouped in the control panel. Modern utility control rooms also have dataloggers or computer systems for scanning and hourly printout of essential operating data which can be programmed to log desired test information.

Preventative maintenance of the control panel instruments, automatic combustion control systems, and plant instrumentation is generally the responsibility of the plant instrument department. Instruments are normally maintained and calibrated on a periodic basis on a frequency dictated by the type of instrument and the manufacturers recommendations. Critical instruments and controls are also given special attention and recalibration whenever required, generally in compliance with operator requests.

Control room, panel board instrument data, as discussed in Section 5.0 and indicated in Table 3, will provide essential information characterizing the mode of operation for individual tests. Before undertaking a NO_x emissions reduction program, a decision should be made concerning which instrument data are important to the program. The instruments selected should then be cleaned, adjusted and recalibrated so that reliable data may be recorded during test runs.

2.7 Emission Measuring Instruments

Control room instrumentation in most power plants, except for O_2 meters, does not include instrumentation for the measurement of CO or NO_x. In carrying out a NO_x emission reduction campaign, reliable O_2, CO, and NO (or NO_x) instruments are a necessity. Existing plant O_2 meters could be used provided it has been ascertained that their readings accurately reflect the average values of the bulk of the gas flowing in the duct. Otherwise, it is recommended that separate instrumentation be obtained and a special sampling system be installed to measure, as a minimum, O_2, CO, and NO_x which are essential to the conductance of a successful NO_x emission reduction program. Ideally a CO_2 analyzer should also be included since it could not only serve as an alternate to the O_2 meter in calculating the diluent effect but the values obtained could be used directly in calculations of boiler efficiency for key test runs. Refer to Section 6.0 for further discussion of the importance of emission measurements.

SECTION 3.0

OPERATING VARIABLES AFFECTING NO_x

Once the boiler, furnace, firing equipment, dampers, controls, instrumentation, etc., have been inspected, and the necessary adjustments, calibration and repairs have been made wherever possible in accordance with the suggested check list, attention can be turned to an operating plan for combustion modifications for the reduction of NO_x emissions and the optimization of boiler efficiency. In formulating the plan, a knowledge of major operating variables and their potential effect on emissions is very helpful. Major operating variables which affect emissions on a pulverized coal-fired utility boiler are listed in Table 1 and are discussed briefly below.

TABLE 1

MAJOR OPERATING VARIABLES AFFECTING NO_x

Major Variables	Settings Affecting NO_x
Load	High, Medium, Low
Excess Air	Normal - Low
Staged Firing	Various Patterns Including OFA
Burner Tilt (Tangential Units)	Up - Horizontal - Down
Burner Registers	Open - Partially Closed
Flue Gas Recirculation	0 to 30% of Gas Flow
Pulverized Coal Fineness	Coarse - Fine

Investigations have shown that NO_x emissions are derived from two sources, i.e., (1) from the nitrogen contained in the combustion air and (2) from the nitrogen chemically combined in the fuel. High temperature fixation of molecular nitrogen in the combustion air occurs in the flame to yield "thermal NO_x." Simultaneoulsy, conversion of the chemically bound nitrogen in the fuel during the combustion process results in "fuel NO_x." Combustion modification variables which affect flame temperature are most effective in controlling thermal NO_x such as, load, burner tilt, burner register settings, flue gas recirculation and pulverized coal fineness. Other combustion variables like excess air and staged firing which limit oxygen availability and affect temperatures in the furnace, reduce both thermal and fuel NO_x emissions. The effect on the latter, however, is limited. Fuel NO_x emissions are strongly dependent on oxygen availability and relatively insensitive to temperature.

3.1 Load

Boiler output, or load, is one of the major operating variables affecting NO_x emissions. On a given unit very little control can be exercised over this variable which is dictated by system demand requirements. NO_x

emissions in general, but not always, increase with load and are highest at maximum load. In extreme cases boiler capacity could be derated to control emissions. Obviously, this is undesirable economically and should be avoided, when possible.

3.2 Excess Air

An excess of combustion air is always supplied to a boiler to ensure complete burnout of the fuel and to provide a "cushion" or safety margin for the operation of the boiler. Excess air is one of the most important operating variables in the control of NO_x, especially when used in combination with staged firing which is discussed later. NO_x emissions are lowest and boiler efficiency highest at lowest excess air levels. Typically, excess air levels on coal-fired utility boilers vary from 18 to 25 percent (3.5 to 5% O_2 in the flue gas). Only recently has it been found possible to reduce oxygen levels on pulverized coal-fired boilers down to 1 to 2 percent to minimize NO_x emissions (and possibly increase efficiency) in short term tests. Normally, levels of 2 to 3% O_2 can be achieved on a long term basis (without exceeding the arbitrary 200 ppm CO level discussed below).

Practical, minimum excess air levels will vary widely from boiler to boiler depending upon furnace design factors, fuel characteristics, boiler and burner condition and operating control flexibility. Minimum excess air level is defined as the level in the boiler flue gases where CO is a maximum of 200 ppm with normal stack plume opacity. Experience has shown that unburned carbon loss at this level is low and that boiler efficiency, in most cases, is not affected. A boiler designed and maintained so that equal, or nearly equal, air to fuel ratios can be established on all operating burners will be able to achieve minimum excess air levels. Thus, burner design, combustion air controls and operating condition of air and fuel controls have an important effect on the level of excess air for proper combustion. Minimum excess air operation is obtained under steady, full load conditions, with all burners operating and with operating time available for "fine tuning" adjustments. Operating at reduced or varying loads will require higher excess air levels. Fuel characteristics such as low volatile, high ash content coal and the degree of coal fineness may also influence air requirements.

Low excess air operation reduces both thermal and fuel NO_x generation and increases thermal efficiency. Establishing practical minimum excess air levels requires measurement of flue gas composition to be assured that combustion is complete (CO should be less than 200 ppm and O_2 probably should not be lower than 1%). Flame stability, shape, and possible impingement should be checked and any affect on steam temperature control (discussed later) should be noted. For long term operation, tendencies toward increased slagging requiring more frequent slag and soot blowing operation should be observed.

3.3 Staged Firing

In the past the pattern of burner usage was dictated largely by load and steam temperature control demands with all burners firing at full load and top row burners kept in service during low load operation to maintain superheat temperature. In the last 10 years staging the firing pattern in combination with low excess air operation has been found to be the most effective technique for limiting NO_x emissions. Various combinations of burners are employed (discussed later) resulting, in general, in an initial combustion zone in the lower part of the furnace where combustion takes place under sub-stoichiometric conditions with burn-out being completed in the upper stage with the admission of overfire air (OFA). In some new boilers designed to meet New Source Performance Standards (NSPS) for NO_x, overfire air ports have been built into the boiler. In existing boilers staging has been simulated using top rows of burners as overfire air ports. The latter technique, while effective, may be limited if full load capability is not possible with top row burners out of service. Staging, however, remains strictly a NO_x emission control technique and would not be practiced where emission controls are not required.

3.4 Burner Tilt

Tilting burners are employed on most Combustion Engineering, Inc. tangetially fired boilers for the express purpose of controlling superheat and reheat steam temperatures. Burners can be tilted within a range of -30° (downwards) or +30° (upwards) from the horizontal position. At low loads, burners are tilted upwards to provide more heat in the superheater and reheater areas. As load is increased the tilt is decreased to keep steam temperatures at the desired control point. Burner tilt has also been found to be an important operating variable in the control of NO_x emissions. Burner angles at or near the horizontal position usually produce less NO_x. This should be checked on each individual unit. The angle of burner tilt for NO_x control, however, may be in conflict with steam temperature control demands. This variable must be investigated to determine optimum tilt angles to satisfy both temperature demands and NO_x emission limits. Usually there is sufficient flexibility in attemperation for steam temperature control to arrive at a compromise between both, although the range of superheat and reheat control may be narrowed in some cases.

3.5 Burner Registers

Fine tuning of the combustion in individual burners is accomplished, in part, by adjustments in burner register position. These adjustments are intended to improve the combustion process, usually by changing direction (but not the flow) of the incoming secondary air. Register adjustment is not for the purpose of combustion air regulation rather adjustments normally increase or decrease burner turbulence. Although burner registers are capable of closing off, they normally are only shut when a burner is out of service.

Changes in burner register adjustment have also been found useful as a variable in reducing NO_x emissions, especially in staged combustion operation. Partial closing of the registers on first stage burners to approximately 40% open while opening the registers on second stage burners (the ones used as overfire air ports) to 80 or 100% open has the effect of reducing the air to the lower burners and increasing the overfire air flow. In most installations where this technique has been used, substantial reductions in NO_x emissions have been achieved. The variable of burner register adjustment as an assist to staged firing for NO_x control, therefore, should not be overlooked.

3.6 Flue Gas Recirculation

Recirculation of up to as much as 30 percent of the flue gas flow is practiced on some boilers for superheat and reheat temperature control. The recirculated gas usually is injected through ports in the furnace walls in the hopper area, having the effect of "blanketing" the furnace walls and increasing the mass flow of gas through the superheater and reheater surfaces holding the steam temperature at the desired control point over a wider load range. Recirculation of flue gas has also been found to be a relatively effective variable for NO_x emission control on gas and oil fired boilers, especially where the flue gas is mixed with the combustion air. In the latter case the oxygen available for combustion is diluted, resulting in lower flame temperatures and reduced NO_x emissions. The effectiveness of flue gas recirculation for NO_x control is not as great when the gas is admitted directly to the furnace. Flue gas recirculation is not as effective on coal-fired boilers because it is relatively ineffective on NO_x formation from fuel bound nitrogen. A conflict also exists with the use of recirculated gas for steam temperature control versus NO_x control, so investigation of this variable is important to establish optimum conditions for both, over the load control range. For these reasons, FGR is not a cost effective means for NO_x control on coal-fired boilers.

3.7 Pulverized Coal Fineness

The fineness of coal pulverization has been noted as a variable which can affect NO_x emissions, at least to a minor degree. Theoretically the coarser the coal, the longer it takes the coarser particles to burn out. The slower diffusion rate of the air into the coarse fuel particle results in longer flames, lower temperature and reduced NO_x emissions. While the fineness of the coal is usually not a variable which is changed but, rather, is a result of mill wear gradually over a period of time, it is nevertheless a factor which can affect NO_x emissions. On most mills coal fineness can be adjusted so this variable, too, bears investigation in the achievement of lower NO_x emissions.

SECTION 4.0

STEAM TEMPERATURE CONTROL

Changes in boiler operating variables, as discussed previously, have a corresponding effect and cause changes in superheat and reheat steam temperatures especially in utility boilers which are of more complex design than industrial type boilers. In order to control superheat, and reheat steam temperatures at constant levels over as wide a load range as possible, special design features are incorporated into utility boiler designs. Some of these have already been discussed above as operating variables but for clarification purposes they will be discussed briefly again relative to steam temperature control. Table 2 lists the arrangements incorporated in utility boiler designs for the specific purpose of controlling superheat and reheat steam temperatures. Note, however, that not all design features will be found on any one boiler.

TABLE 2

SUPERHEAT AND REHEAT STEAM TEMPERATURE CONTROL FEATURES

- Attemperation
- Burner Tilt (Tangential Boilers)
- Biasing Dampers
- Flue Gas Recirculation
- Excess Air
- Furnace Slag Blowers

4.1 Attemperation

Most modern boiler designs incorporate an attemperator (or desuperheater) between the primary and secondary superheater sections for the purpose of decreasing the temperature developed in the primary section and controlling the final superheat steam temperature over a wider range of boiler load. The superheater is designed for full temperature at some partial load point. The excessive superheater surface results in correspondingly high temperatures at higher loads and the excess temperature is "trimmed" off by the attemperator by spraying water into the steam in sufficient quantity to maintain final steam temperature emitting from the secondary superheater at the desired control set point. This arrangement is a relatively delicate type of control and is sensitive to changes in gas temperature and mass flow of the gas across the superheater and reheater. Variation in excess air and flue gas recirculation for NO_x control affects both the mass flow and temperature of the gases passing through the unit which will have a corresponding affect on attemperation. A trade off in NO_x emission control with steam temperature control, therefore, may be necessary in some boilers. The effect could also merely be a narrowing of the superheat and reheat temperature control range.

4.2 Burner Tilt

As indicated above, most Combustion Engineering, Inc. tangentially-fired utility boilers incorporate devices so that the burners may be tilted through an arc range of -30° to +30° from horizontal. Tilting the burners upward so they fire more directly into the superheater puts more of the heat near the superheater entrance, effectively bypassing a portion of the furnace, making it possible to maintain steam temperatures at lower loads. As the load increases and less heat is needed in the superheater or reheater, the burner angle is depressed to maintain temperature. As previously indicated, the burner tilt angle can have an appreciable effect on NO_x emissions with lowest emissions normally being obtained with burners firing close to the horizontal position. Optimum points may be worked out so that the desired steam temperature can be maintained with minimum NO_x emissions.

4.3 Biasing Dampers

Some boilers are designed with the superheater and reheaters side-by-side, rather than in tandem in the direction of gas flow which is more common in modern designed boilers. On boilers with superheaters and reheaters side-by-side one method of steam temperature control employed consists of an arrangement of biasing dampers installed downstream of the convection section which can be varied to divert more of the flue gas flow from the superheater side to the reheat side and vice versa. This type of steam temperature control should be independent of NO_x control techniques but, again, a change in gas temperature or mass flow as a result of NO_x combustion modifications will affect steam temperature control, thus requiring readjustment.

4.4 Flue Gas Recirculation

In past years flue gas recirculation (FGR) was a popular form of steam temperature control. In recent years this type of control seems to have lost favor especially on pulverized coal fired boilers due to fan problems and difficulties in handling dust laden gases. On most units where FGR is employed, only a small amount (or zero) of gas is recirculated as load drops off to keep superheat and reheat temperatures at the control set point. Gas recirculation is most effective for NO_x control when mixed with the combustion air before the burners. However, when FGR is used solely for steam temperature control, it is usually injected into the hopper zone. In any event, the amount of gas recirculated can affect NO_x emissions and optimum conditions must be established to satisfy both steam temperature control and NO_x emissions. As mentioned before, flue gas recirculation is of limited effectiveness for NO_x control with coal-fired boilers because it does not retard conversion of fuel nitrogen.

4.5 Excess Air

Varying the amount of excess air at a given load affects both the flue gas temperature and the gas mass flow which has a corresponding effect on superheat and reheat steam temperatures. Some boilers have been designed employing this principal for steam temperature control. Fortunately, not too many units of this type are in existence since one of the most effective NO_x control techniques employs low excess air in combination with staged combustion to achieve low NO_x emission values.

4.6 Furnace Slag Blowers

On pulverized coal fired boilers, some of the ash in the coal deposits on the furnace walls. Eventually, with time, these deposits may form sizeable accumulations of slag which can effectively blanket the furnace walls, decrease the heat absorption in the furnace and result in increased gas temperatures entering the superheater and reheater sections. If the process is allowed to continue, a point would be reached where superheat and reheat temperatures could not be kept in control by the means discussed above and the unit would have to be taken out of service to clean the furnace. However, slag blowers are strategically placed in the furnace and are operated on a regular basis (at least once per shift) to remove slag accumulations and keep the furnace in a "clean" condition. Thus, the slag blower operating cycle is an important factor in keeping steam temperatures under control. Under low NO_x emission conditions there may be a tendency for slag accumulations to build up faster requiring more frequent furnace slag blower operation.

It is also important, from a steam temperature control standpoint, to maintain superheater and reheater surfaces free of ash deposits which might interfere with heat transfer or the flow of gas through these passages. Soot blowers are provided for this purpose in the superheater and reheater sections and their operating schedule is similarly influenced by the same factors discussed above.

SECTION 5.0

OPERATING TEST DATA

In conducting a program to reduce NO_x emissions from a boiler, it is essential that pertinent control room board data, emission measurements and operating parameters be thoroughly documented to completely characterize each test. This would include such information as burner register settings, burner tilt angle, opacity, observations on flame and slagging, notes on staging patterns, etc. The recorded test data will become a permanent record of NO_x emission capabilities which may be used to plan subsequent tests. More important, the data obtained will permit exact repetition of operating conditions after determining which mode of firing resulted in optimum NO_x reduction capability.

A sample data sheet, illustrative of the type of test data which should be obtained, is shown in Table 3. Instrumentation will vary, of course, with individual boilers and the data sheet should be expanded to include other pertinent operating data wherever possible.

It should be noted, with reference to Table 3, that large utility boilers usually have split flue gas streams downstream of the economizer. Thus, there may be two airheaters, two ID and FD fans, etc. Also each boiler will have from 4 to 10 pulverizers depending on size of the unit. Test data, therefore, should be recorded for each piece of equipment in the installation.

TABLE 3. BOILER TEST DATA

Utility ______________________________ Station ______________________

Boiler No. ____________________ Fuel ______________________________

Date								
Test No.								
Time								
Load, MW								
Stm. Flow, Lb./Hr.								
Air Flow, Lb./Hr.								
Feed Water Flow, Lb./Hr.								
Coal Scale, Start								
Coal Scale, Finish								
Steam Press., PSIG								
Superheat Temp., ^{o}F								
Reheat Temp., ^{o}F								
SH Attempt. H_2O Flow, Lb./Hr.								
RH Attempt. H_2O Flow, Lb./Hr.								
Burner Tilt, Deg.								
Overfire Air Damper Position								
Overfire Tilt, Deg.								
Burner Register Position								
FD Fan Amps								
ID Fan Amps								
Furn. Press., in H_2O								
Windbox/Furn. Diff., in H_2O								
Airheater Diff., in H_2O								
Pulverizer Temp., ^{o}F								
Airheater Air in Temp., ^{o}F								
Airheater Air Out Temp.,								
Airheater Air in Temp., ^{o}F								
Airheater Gas Out Temp., ^{o}F								
Opacity: %								
O_2 Percent								
CO, PPM								
NO_x, PPM								
Staging Pattern								
Slagging Observ.								
Remarks								

SECTION 6.0

EMISSION MEASUREMENTS

In carrying out a NO_x emission reduction program, it is essential that accurate and reliable emission measuring equipment be used. This equipment must be located such that a representative sample of the boiler gas stream is measured. As a minimum, equipment for measurement of O_2, CO and either NO or NO_x is required. CO_2 may be measured as an alternative to O_2 for the purpose of computing the diluent effect.

Older, pre-NSPS sources are usually equipped with only an O_2 measurement system, with the sensor/probe located in the ductwork between the economizer and airheater. If this system is to be used for the NO_x reduction program, it must be evaluated in terms of accuracy and reliability. If it is used, the NO_x and CO measurement equipment must be located at the same place. U.S. EPA regulations concerning the installation, operation and maintenance of continuous monitoring systems provided in "Performance Specification 2 (PS2), 40 CFR part 60-as amended" are recommended for guidance. If the source already has a certified continuous monitoring system, it should be used for the NO_x reduction program.

If temporary emission measurement equipment must be installed for the proposed program, consideration should be given to equipment which can operate unattended for extended periods of time. Provisions should also be made for some form of automatic data recording, such as stripcharts. If the NO_x reduction program will be used for a compliance demonstration, this type of installation is normally not acceptable unless approved in advance by the appropriate agency. Where compliance tests are required, Federal Reference Methods (as mentioned above and in Appendix D), must be used for confirmation.

The installation and operation of any emission measurement equipment should be under the supervision of appropriate, qualified personnel. Appendix D covers the essential details and methods for measuring combustion product pollutants.

6.1 Comparing NO_x Emissions

Nitrogen oxide (NO_x) emissions for any given test are measured on a volumetric basis at the specific excess air conditions under which the test is conducted. Since excess air is varied to reduce NO_x emissions, the data developed are not readily comparable, and the results are obscured by the dilution effect of the excess air in the flue gases when reported in parts per million, ppm. For example, when excess air is decreased, NO_x emissions also decrease but the apparent measured value may seem higher than expected due to the simultaneous effect of concentration of the flue gases (less O_2). Conversely, experience shows that NO_x levels increase as excess air increases, yet measured values may not appear too high since NO_x emissions are being diluted as excess air increases. It is important to understand the diluting effect on NO_x (and other) emissions emitted from the boiler and the need for a common comparison basis when results are reported as parts per million.

Early investigators resolved this matter by converting and reporting all emission results on a common basis of 3% O_2 in the flue gases. This has carried over and been accepted by the industry and has been adopted by the EPA as standard practice for evaluating and comparing emissions. After average oxygen and nitrogen oxide emissions are established for a particular test, the NO_x emission value is corrected to the 3 percent oxygen basis by multiplying by a correction factor determined as follows:

$$\text{correction factor} = \frac{21\text{-}3\%\ O_2 \text{ (standard basis)}}{21\text{-}\%O_2 \text{ (average for test)}}$$

$$= \frac{18}{21\text{-}\%O_2 \text{ (average for test)}}$$

For example, emissions for a given operating mode average 485 ppm NO_x with an average of 1.6 percent O_2 in the flue gases:

Therefore:

$$NO_x \text{ (at 3\% } O_2) = NO_x \text{ (at test conditions) x correction factor}$$

$$= 485 \times \frac{21-3}{21-1.6}$$

$$= 485 \times \frac{18.0}{19.4}$$

$$= 485 \times .9278$$

$$= 450 \text{ ppm}$$

NO_x emissions measured on a volumetric basis in ppm, may be converted to a weight and unit of heat input basis through the use of F factors. The use of the F factor in calculating particulate emission levels from new stationary sources was promulgated in the October 6, 1975 Federal Register. Other publications of the F factor methods of conversion are (1) EPA report EPA-340/1-77-015 "Standards of Performance for New Stationary Sources," November 1977 and (2) EPA's Air Pollution Training Institute, Manual 450, "Source Sampling for Particulate Pollutants," January 1978. The purpose of the F factor is to reduce the amount of data necessary to calculate emissions in terms of the standard expressed as $lbs/10^6$ Btu, heat input. Procedures for the conversion of emissions from a dry (usual) to a wet basis are also detailed in the F factor publications mentioned above.

Emissions given as mass per unit of heat input or mass of fuel burned do not need to be corrected for dilution. However, most continuous monitors provide results in units of ppm.

SECTION 7.0

CARRYING OUT THE NO_x REDUCTION PROGRAM

At this point, it is assumed that the boiler on which it is desired to reduce NO_x emissions has been inspected in accordance with the suggested check list, and items needing repair, adjustment or calibration have been attended to insofar as may be feasible. It is also assumed that control, recording and emission measuring instrumentation has been inspected and test data sheets have been prepared to record the important test data.

The foregoing reviewed the major operating variables, and the changes which NO_x combustion modifications would be expected to have on emissions and superheat and reheat temperatures. Before proceeding further, consideration should be given to whether the objective of the NO_x emission reduction plan is for compliance or merely to establish the emission capabilities of the boiler. Establishment of these goals will help to determine how deep a cut may be necessary. The suggested plans and procedures which follow, probe the maximum NO_x emission reduction capabilities of the boiler which may be relaxed if wide latitudes in complying with regulations are found to exist.

It is not within the scope of this guideline to provide the necessary, detailed combustion control knowledge required to carry out a NO_x emission program; rather, it is assumed that competent boiler operators well versed in boiler operation are in charge. Combustion modifications and operation for NO_x emission control are different than for normal, routine operation. For instance, excess air levels are lower than for normal operation and with normal firing no attempts are made to stage the combustion process or to make adjustments in burner registers other than those recommended by boiler manufacturer's operating instructions. Therefore, a test program plan is necessary, even for experienced operators, where a step-by-step procedure is followed for each test, leading in a progressive fashion to the establishment of optimum efficiency and "low NO_x" emission operating conditions. A word of caution is necessary here, however. Changes should be made in small, incremental steps so as not to lose control of the operation at any time.

7.1 Test Program Plan

One of the first tasks in the approach to a successful NO_x emission reduction program is to develop a test program. Operating variables (which are specific for each boiler) should be carefully reviewed for inclusion in the experimental program. This is best illustrated by the example in Table 4 showing a simplified experimental test program plan for a 125 MW front wall fired boiler, firing pulverized coal in 16 burners arranged in a matrix of four burners wide by four high as shown in Table 4. Operating variables included in the plan are:

TABLE 4. EXPERIMENTAL TEST PLAN

Pattern Firing	Secondary Air	L_1 - Full Load (125 MW)				L_2 - Reduced Load (110 MW)			
		A_1 - Normal Air		A_2 - Low Air		A_1 - Normal		A_2 - Low Air	
		20% Open R_2	60% Open R_1	20% Open R_2	60% Open R_1	20% Open R_2	60% Open R_1	20% Open R_2	60% Open R_1
S_1	16 Coal 0 Air Only	(3) 2.8% 610	(1) 3.2% * 577	(4) 1.9% 505	(2) 2.0% 491	(15) 4.9% 681	(13) 4.8% 629	(16) 2.8% 464	(14) 2.7% 450
S_2	14 Coal D_1 D_4 Air	(5) 3.8% 632	(7) 4.0% 558	(6) 2.0% 372	(8) 1.5% 406				
S_3	14 Coal A_1 A_4 Air	(11) 4.5% 532	(9) 4.1% 518	(12) 1.7% 345	(10) 2.7% 368				
S_4	12 Coal A_1 A_2 A_3 A_4 Air					(17) 4.5% 399	(19) 4.5% 460	(18) 2.7% 297	(20) 3.0% 345
S_5	12 Coal A_1 A_4 B_2 B_3 Air					(23) 4.9% 496	(21) 4.4% 480	(24) 3.4% 306	(22) 2.6% 342

* Numbers in parentheses in boxes are test run numbers (in sequence of testing). Figures in boxes are average percent O_2 during test and ppm NO_x emissions corrected to 3% O_2 dry.

NOTE: Experimental test plan is also used as a "Score Sheet." Test results shown in boxes only become available as each test is completed.

Pulverizer-Burner Configuration

Mill	Burner No. 1	2	3	4
A-Top Row	0	0	0	0
B-2nd Row	0	0	0	0
C-3rd Row	0	0	0	0
D-Bottom Row	0	0	0	0

Load - High (L_1), intermediate (L_2)
Excess Air - High or normal (A_1) and low (A_2)
Burner Registers - Normal setting, 60% open (R_1)
- Closed down, 20% open (R_2)
Staging Patterns - S_1, normal firing, all burner in service
- S_2, staged, two burners, D_1 and D_4 on air only
- S_3, staged, two burners, A_1 and A_4 on air only
- S_4, staged, four burners, A_1, A_2, A_3 and A_4 on air only
- S_5, staged, four burners, A_1, A_4, B_2 and B_3 on air only

The test plan in the example shown in Table 4 calls for testing at two loads only, i.e., maximum rated load and intermediate load. In many cases testing at a low load or additional intermediate ratings may be desirable. In such cases, the test program plan should be expanded accordingly. Also, as explained previously, testing at each stage is normally conducted at two excess air levels only; i.e., normal (relatively high) and minimum (low excess air) as defined by the 200 ppm maximum CO level. Furthermore, it should be pointed out that the minimum excess air level most likely will vary on a given boiler depending on the particular combustion modification operating mode, coal, condition of the boiler and combustion system, etc.

Testing at two different burner register settings only are included in the simplified test plan example. With more complicated burner arrangements, testing at additional burner register settings may be required to adequately optimize the effect of burner register adjustments on NO_x emissions, resulting in the necessity to further expand the test plan.

Several different staging patterns are included in the test plan example shown in Table 4. Since, initially, the effect of different burner arrangements on NO_x emissions is unknown, various combinations of burners must be tried until the optimum configuration becomes apparent. It is known that wider separation of burners (improved cooling between burners) and overfire air has a beneficial effect on NO_x emissions. Various burner staging arrangements to accomplish these objectives should be included in the test plan in order to develop the optimum combustion mode. Larger more complicated boilers with greater numbers of burners may require more extensive staging pattern investigation than those shown in the simplified plan in Table 4. However, sufficient information on staging the combustion process should be available from Table 4 to develop a more extensive test program. Examples of more complete experimental test programs are given in Appendix A. Actual test plans and results can be found in References 1 & 2.

7.2 The ABC's of Reducing NO_x Emissions

In any NO_x emission reduction program three fundamental, basic steps are taken at each incremental phase of the program. These steps are illustrated in the flow plan in Figure 1 as the ABC's of NO_x reduction. Essentially the approach is the same at any given point with the three steps being repeated over and over again, but under different operating conditions, whether they occur at the beginning, at the end, or at some intermediate stage of the program. An understanding of the objectives of the ABC approach, therefore, is most important.

Referring to Figure 1, the three basic steps which are repeated at each stage of the program for each combustion configuration are:

(A) Establishment and characterization of the operating mode.

(B) Measurement of NO_x emission at normal (or high) excess air operation for the operating mode established in A.

(C) Reduction of excess air to minimum levels and measurement of NO_x emissions.

Considerable thought must obviously be given to the establishment of the operating mode regarding potential effects on NO_x emissions. Step A, therefore, is of utmost importance in planning each phase of the NO_x reduction program. For instance, the effect on NO_x emissions of closing burner registers 20 to 40% from normal may not be readily predictable. What may be assumed to have a beneficial effect may in actuality have an adverse effect on NO_x emissions. A series of burner register positions (different combustion modes) must consequently be incorporated into the overall NO_x investigation program in order to fully assess and optimize NO_x emission reductions. Similarly other operating variables must also be investigated separately.

Once the operating mode has been established and characterized, the second step (step B) is to measure NO_x emissions for the operating mode selected at "normal" excess air operation. The immediate question which arises is "what is normal excess air"? Most utility boilers are designed to operate with about 17 to 20 percent excess air, i.e., 3.5 to 4.0 percent O_2 in the flue gases. In the field these boilers have been observed to be operating in excess of design conditions, generally at about 4 to 5 percent O_2 and sometimes higher. In any event, measurement of NO_x emissions in step B are intended to be made at the excess air level which the boiler normally operates (usually relatively high excess air conditions).

In step C the potential for reducing NO_x emissions for the operating mode established in step A is explored by reducing excess air to a minimum and again measuring NO_x emissions (Step C). This is done by reducing the combustion air in small incremental steps, keeping careful watch of O_2 and CO levels. Experience shows that the baseline CO level for normal operation on utility boilers ranges between 30 and 40 ppm. As the air rate is decreased, oxygen levels will be observed to drop with very little change in CO readings. A point will be reached where CO levels commence to increase. Further decreases in the combustion air should then be made until CO values (from the lowest O_2 probe if multiple gas sampling ports are used) reach a level of about 200 ppm. This point is defined as the minimum excess air level. Reducing excess air beyond this point normally will increase stack opacity conditions to unacceptable levels. On some boilers under some operating conditions, especially at low

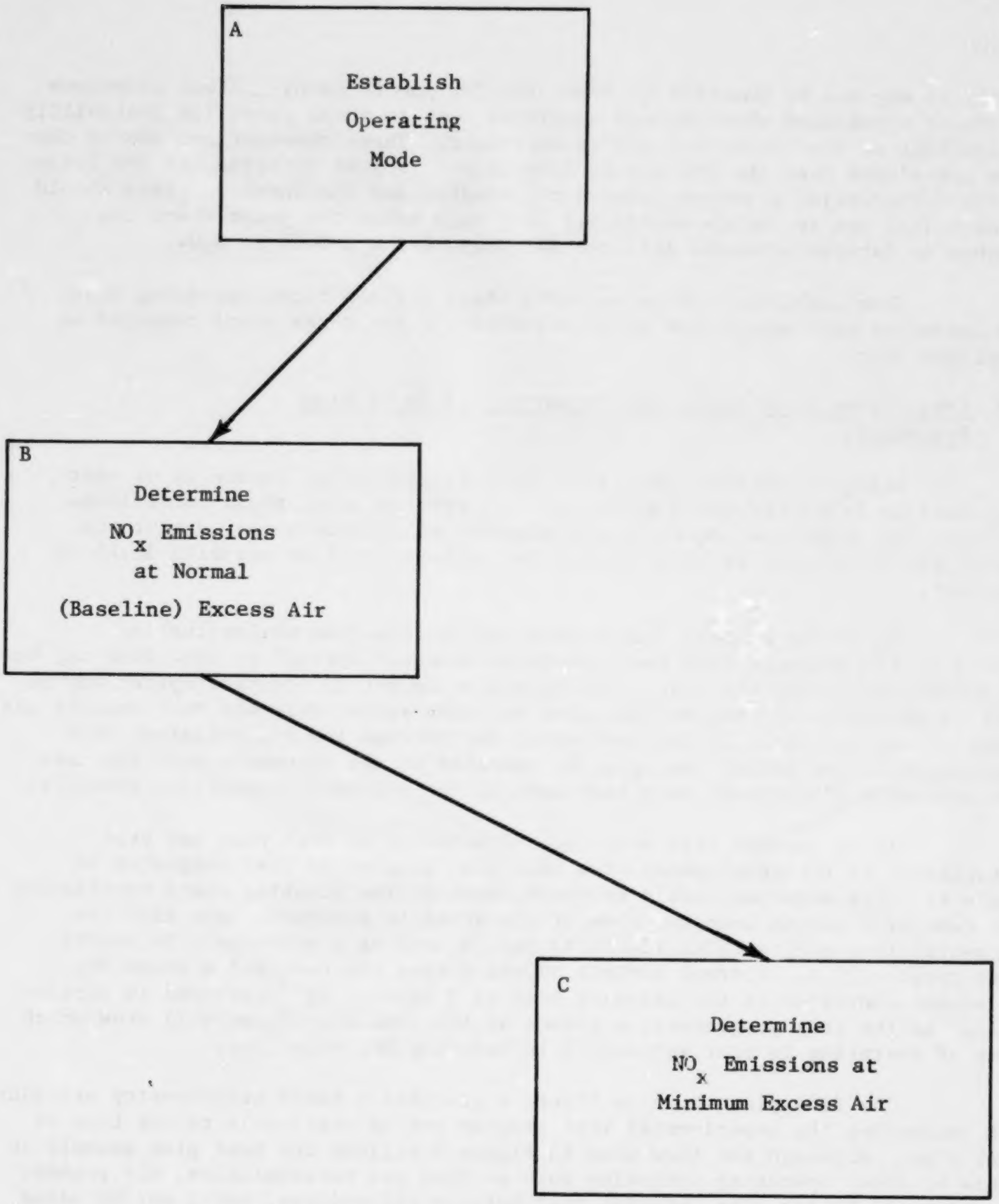

A
Establish Operating Mode
B
Determine NO_x Emissions at Normal (Baseline) Excess Air
C
Determine NO_x Emissions at Minimum Excess Air

Figure 1. Fundamental Steps in Reducing NO_x Emissions.

loads, it may not be possible to reach the 200 ppm CO level. Stack emissions and flame appearance observations should be made in these cases for instability indications as the combustion air is decreased. These observations should then take precedence over the 200 ppm CO limitation. A good criteria for the latter is the differential pressure between the windbox and the furnace. Care should be exercised not to reduce excess air very much below the point where the windbox to furnace pressure differential drops below 1 inch of H_2O.

This completes the three (ABC) steps for the first operating mode. A new operating mode would then be established and the three steps repeated as described next.

7.3 Basic Steps in Reducing NO_x Emissions - Step by Step Procedures

Since combustion conditions are most stable and secure at or near full load it is advisable to start the test program under these conditions. Besides, NO_x emissions generally are greatest at maximum boiler output and one of the objectives is to determine the maximum baseline emission level on the unit.

Operating at full load, normal conditions, the boiler/turbine should be disconnected from the "Automatic Dispatch System" so that load may be held constant during the test. The automatic combustion control system may be kept on automatic as long as load does not vary appreciably and thus obscure test results. Later, after firing conditions for optimum low NO_x emissions have been defined, the boiler can again be operated in the automatic position once the necessary adjustments have been made in the automatic combustion controls.

It is assumed that some logical sequence of test runs has been established in the development of a test plan similar to that suggested in Table 4. This sequence should be established in the planning stage considering the ease of changing from one mode of operation to another. Note that the suggested test program plan (Table 4) may be used as a scoresheet to record test results, i.e., average percent oxygen during the test and average NO_x emissions converted to the standard base of 3 percent O_2 (explained in Section 6.1). As the test progresses, a glance at the test plan sheet will show which mode of operation is most successful in reducing NO_x emissions.

The flow plan shown in Figure 2 provides a basic step-by-step procedure for conducting the experimental test program and is applicable to any type of test plan. Although the flow plan in Figure 2 follows the test plan example in Table 4, other operating variables such as flue gas recirculation, air preheat temperature, burner tilt, biasing fuel between pulverizers, etc., may be added to the plan and the same procedures followed as described below in the examples for burner register settings or staged combustion patterns.

- Baseline Operation - Full Load

At the start (step A) with the boiler operating normally at full load, the first task is to completely characterize the conditions under which the boiler is operating regarding load, burner register setting, number of

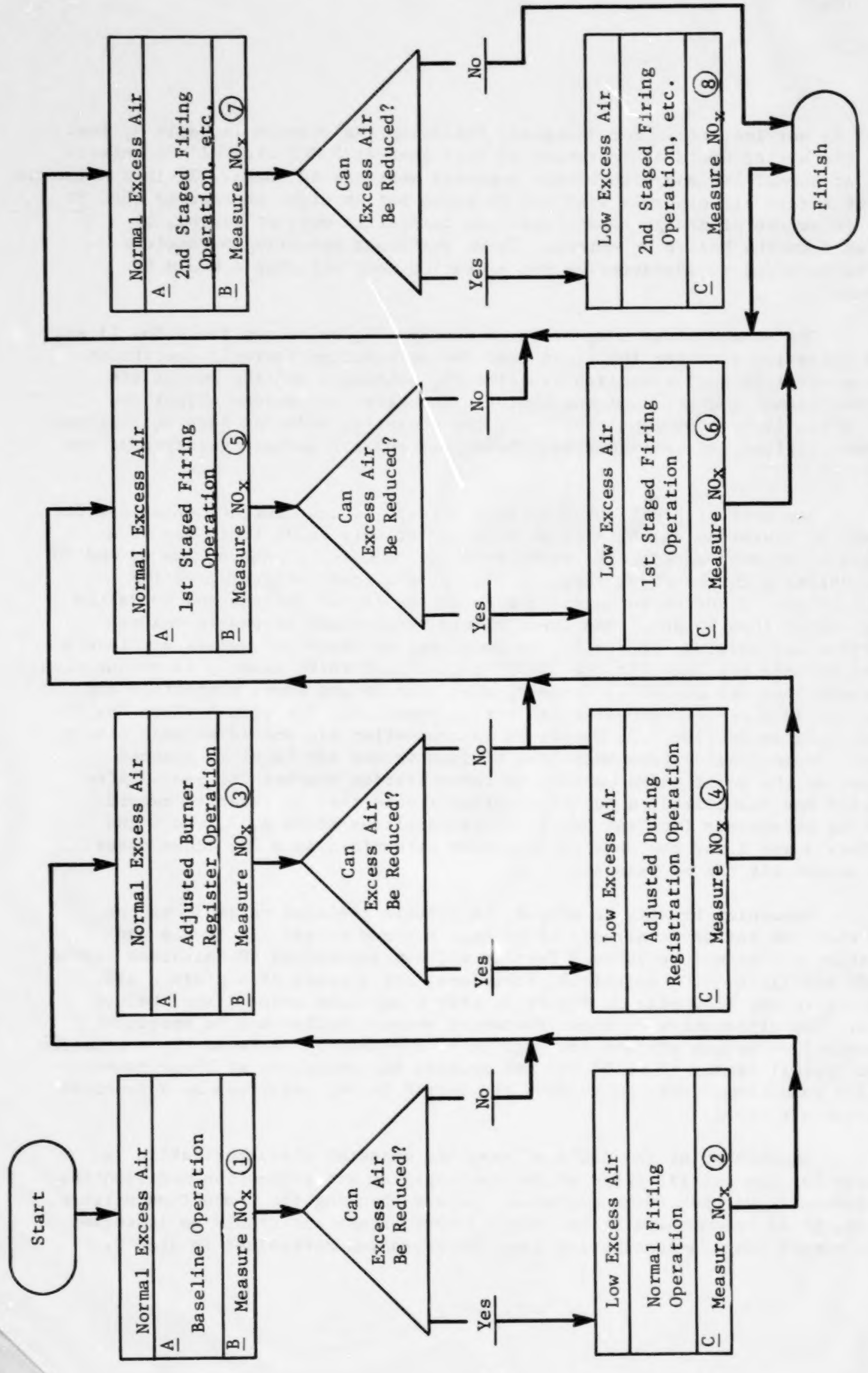

Start
Normal Excess Air
A Baseline Operation
B Measure NO$_x$ ①
Can Excess Air Be Reduced?
Yes
No
Low Excess Air
Normal Firing Operation
C Measure NO$_x$ ②
Normal Excess Air
A Adjusted Burner Register Operation
B Measure NO$_x$ ③
Can Excess Air Be Reduced?
Yes
No
Low Excess Air
Adjusted During Registration Operation
C Measure NO$_x$ ④
Normal Excess Air
A 1st Staged Firing Operation
B Measure NO$_x$ ⑤
Can Excess Air Be Reduced?
Yes
No
Low Excess Air
1st Staged Firing Operation
C Measure NO$_x$ ⑥
Normal Excess Air
A 2nd Staged Firing Operation, etc.
B Measure NO$_x$ ⑦
Can Excess Air Be Reduced?
Yes
No
Low Excess Air
2nd Staged Firing Operation, etc.
C Measure NO$_x$ ⑧
Finish

Figure 2. Basic Steps in Reducing NO$_x$ Emissions.

burners in service, etc. For instance, following the example in Table 4, test No. 1, the boiler would be operating at full load (125 MW) with all 26 burners firing at normal air and with burner register settings 60% open. At this point the level of excess air probably will not be known but it might be assumed that it may be in excess of design conditions. An indication may, of course, be obtained from the boiler O_2 meters. These pertinent operating parameters would be recorded to characterize the operating mode and step A would be complete.

The second task (step B) is to measure NO_x emissions (test No. 1) and record operating data for the first test run at baseline (normal) conditions. The data obtained will establish baseline NO_x emissions and the excess air level for normal operation of the boiler. The first and second objectives (steps A and B) are now complete, i.e., the operating mode has been established and characterized and emissions have been measured for normal operation of the boiler.

The next step will be the first attempt at reducing NO_x emissions for the mode of operation established in step A. At this point there may be a question of whether excess air can be reduced. A quick glance at the O_2 and CO values obtained in the first test run will give a good indication of the possibilities. If O_2 measurements are in excess of 3.5 percent and CO values are no higher than 40 ppm, then there should be adequate leeway to reduce combustion air levels. Generally, as mentioned previously, excess air levels on most boilers are high (in the 20-25% region) and there usually is no question that reductions can be made. Assuming that this is the case, combustion air should now be decreased to establish firing conditions for step C (Test No. 2). As described in Section 7.1, decreases in combustion air should be made slowly in small controllable steps until the minimum excess air level is reached (defined as the point where maximum CO concentration reaches 200 ppm). After operation has stabilized, a set of readings should then be taken to record operating parameters for Test No. 2. This completes steps A, B, and C and Test Nos. 1 and 2 for the mode of operation determined in A for those cases where excess air can be reduced.

Returning briefly to step B, in certain isolated cases it may be found that the boiler is already at or near minimum excess air levels and combustion air cannot be reduced further without increasing CO emissions beyond the 200 ppm limit. NO_x emissions, therefore, are already at a minimum and, referring to the flow plan in Figure 2, step C has been accomplished before step B. The alternative in those instances where a boiler may be operating optimumly (low excess air and low NO_x) is to arbitrarily increase the combustion air to typical levels (4 to 5% O_2) and measure NO_x emissions at these psuedo baseline conditions (step B) to show the spread in NO_x emissions as a function of excess air level.

At this point the ABC's of baseline emission characterization is complete for the initial phase of the test program and combustion modification techniques are waiting to be explored. Before changing the combustion pattern, however, it is recommended (after step C) that excess air should be increased to the normal range approximating baseline operation determined in step B.

Sufficient margin of safety will thereby be provided to make the changes for the next operating mode to be investigated and to accommodate unexpected or abrupt changes in combustion without losing control of the operation.

Following the flow plan in Figure 2, changes may now be made in the operating mode, such as closing burner registers down from 60 to 20 percent open, as suggested in the test plan in Table 4. Upon completion of the adjustments a new operating mode will have been established and characterized (repeat of step A). NO_x emissions and other operating data (Test No. 3) are then recorded (repeat of Step B) for the new operating mode. Afterwards, excess air may again be slowly reduced to minimum levels (200 ppm CO max) and pertinent operating data recorded (Test No. 4) in a repeat of step C. Test Nos. 3 and 4 of the suggested test plan in Table 4 will be complete at this stage and the boiler will be ready for further testing after again increasing excess air to baseline conditions.

An appraisal of the results obtained in Test No. 4 may not give a clear-cut indication of an improvement in NO_x emissions as indicated in the flow plan in Figure 2. A decision must be made at this point whether data on additional burner register settings is warranted to optimize NO_x emission reductions. The full effect of burner register settings may not be apparent until staged firing runs are completed. Better judgment of these effects, therefore, may be delayed until staged firing runs are completed. However, if further data are desirable, other burner register settings can be attempted at this time and the process described above should be repeated for each of the new settings. If sufficient information does appear to be available, the test program may proceed to the next phase, "investigation of the effects of staging the combustion process on NO_x emissions." At this point baseline operating conditions (S_1 in Table 4) at full load and two different burner register settings have been characterized. Also, NO_x emissions have been determined for normal and minimum excess air operation.

- Staged Combustion - Full Load

Staging the combustion process to reduce NO_x emissions on boilers not equipped with overfire air ports, as discussed below, requires taking burners out of service in various combinations. These burners are used as air ports by stopping the coal flow to the burner but permitting air flow to the furnace to continue, generally (but not always) with the burner dampers in the wide open position to obtain the optimum effect. Individual burners on some boilers equipped with burner line valves can be removed from service by shutting the burner line valve. Other burners supplied by the same pulverizer can be kept in service firing coal in the usual manner. The choice of firing patterns on such units can be varied widely as desired. Recent trends in fuel burning equipment design have eliminated burner line valves due to problems experienced with this type of equipment. Staging the firing pattern in units without burner line valves is limited to removing all burners from service which are served by an individual pulverizer. This, of course, restricts the choice of firing patterns and, in many instances, dictates testing for NO_x emission reduction at lower loads. Modern design practice, however, permits full load operation in most units with one pulverizer out of service. Greater flexibility in the choice of staged firing patterns is thereby accorded in these units. Appendix A covers examples of staged firing where entire rows of burners served by an individual pulverizer must be removed from service. The following example discusses staged firing patterns permitted by individual burner removal.

With combustion air restored to normal levels after test No. 4, adjustments may now be made in boiler operating conditions to stage the combustion process. Following the test plan in Table 4, coal supply is shut off to the outside burners D_1 and D_4 in the bottom row of burners as shown on the burner configuration diagram in Table 4. Air supply to these burners is opened wide so that combustion air only is introduced through the D_1 and D_4 burners underneath the combustion zone. Burner registers remain at 20% open on the other burners; the same setting prevailing after test No. 4. After completion of these adjustments, the first staged firing combustion modification pattern (S_2, Table 4) has been characterized (Step A) and the boiler is ready for determination of NO_x emissions.

NO_x emission data are then recorded for staged firing pattern S_2 with the boiler operating at full load under normal air conditions and burner registers set at 20% open on the burners firing coal. After these recordings are complete, excess air level is again cautiously reduced to minimum levels following previous guidelines and NO_x emission data is again recorded. Test Nos. 5 and 6 (Table 4) will then be complete for staged firing pattern S_2 and 20% burner register settings.

Following the flow plan in Figure 2, excess air level is again increased to normal before making any adjustments in the combustion pattern after which burner registers (except on D_1 and D_4) are reset to the 60% open position. NO_x data are then recorded for test No. 7 (normal air, 60% register setting) followed by a reduction in excess air to minimum levels and recording of data (test No. 8) as previously described. NO emission reduction capabilities for the S_2 staged firing pattern, at this point, have been determined for 20% and 60% burner register positions. It may be desirable to investigate further the optimization of burner register positions. If so, additional tests must obviously be run in accordance with the procedures detailed. However, at this point, it may be advisable to proceed with the exploration of alternate staging patterns when more data will be available to judge the best route for further exploration.

After test No. 8, excess air is restored to normal in preparation for a change to staged firing pattern S_3 (Table 4). Burners D_1 and D_4 are placed back in service, readjusting the burner registers to 60% open, and top burners A_1 and A_4 are taken out of service. Secondary air supply on burners A_1 and A_4 are opened wide resulting in a supply of air over the top of the combustion zone. This produces a two-staged effect with combustion at fuel rich conditions in the bottom of the furnace with an excess of air at the top of the combustion zone for burn out. As mentioned previously, in this example, the boiler does not have the capability of maintaining full load with the four top burners (A_1, A_2, A_3 and A_4) out of service. A compromise with the two "wing" burners (A_1 and A_4) used as air ports is, therefore, investigated.

After combustion conditions have stabilized, NO_x emission data is recorded for test No. 9 at full load, staged firing pattern S_3, burner registers set at 60% open (except on burners A_1 and A_4 which are wide open). This is followed by test No. 10 at minimum excess air in the same manner as previously described. Excess air is then increased to normal, burner registers are closed down to 20% open (except on A_1 and A_4) and emission data recorded for tests 11 and 12 following the same procedures. This completes definition of the S_3 staged firing pattern for 20 and 60% open register positions as indicated in the test plan example in Table 4. It will be desirable to investigate other staged firing patterns in order to optimize NO_x emissions. For the sake of clarity, however, these will not be discussed here except to indicate a few possibilities, such as, using burners A_2 and A_3, B_1 and B_4, B_2 and B_3 etc. as air ports on air only. Investigative procedures remain the same for these patterns, as previously described and as shown on the flow plan in Figure 2. Information in Appendix A provides further details on more extensive testing.

- Baseline Operation - Reduced Load

Attention is now directed to investigations at reduced load as shown in Table 4. The choice of boiler load at which the tests will be conducted should be determined by the load carrying ability of the boiler with one pulverizer out of service. In the example this means four burners out of service, since each pulverizer supplies four burners. The boiler operators, who are well aware of these capabilities, should be consulted to establish these conditions. In the test plan shown in Table 4, maximum boiler load with four burners out of service was established at 110 MW.

With all pulverizers and burners in service but load on the boiler reduced to the 110 MW level and excess air and burner register settings reset to normal and 60% open positions, respectively, NO_x emission data are recorded for test No. 13. After reducing excess air to the minimum level, data for test No. 14 is recorded. Following described procedures, burner registers (except those on air only) are again closed down to 20% open and test Nos. 15 and 16 are run in sequence at high air and low air, respectively. This characterizes and establishes baseline conditions and emissions at reduced boiler load at 20 and 60% open register settings with all burners in operation.

- Staged Combustion - Reduced Load

After test No. 16, excess air is increased to normal and the pulverizer supplying burner row A is removed from service. Secondary air dampers and registers on burners A_1, A_2, A_3 and A_4, however, are opened wide to supply a sheet of combustion air over the top of the burner zone to effect complete two-stage combustion. Burner registers in the bottom three burner rows remain set at 20% open as they were for test No. 16. Cramping down on the combustion air flow in the bottom burners increases the flow of air to the top burner row enhancing the two-stage effect. Test Nos. 17 and 18 are then run sequentially, as in the previous examples, and NO_x emission data are recorded for staged combustion pattern S_4 (Table 4). Excess air is then again increased to normal and burner registers on the active burners are adjusted to the 60% open position. Tests 19 and 20 are then recorded completing data on the S_4 staged firing pattern.

Referring to the test plan in Table 4, the boiler is again in readiness to proceed with the second reduced load, staged firing pattern (S_5) after excess air is restored to normal levels. Pulverizer A is placed in service firing through burners A_2 and A_3 with registers adjusted to 60% open. Coal flow is shut off on burners A_1 and A_4 and registers remain 100% open to combustion air flow. Coal flow on burners B_2 and B_3 is shut off and registers are opened wide. Overfire air is thus introduced through burners A_1, A_4, B_2 and B_3 with registers on these burners 100% open. All other burner registers are maintained at 60% open for test Nos. 21 and 22. In the manner described above, test Nos. 21 and 22 are run followed by a change in burner register settings to 20% open on active burners and the recording of NO_x emission data for test Nos. 23 and 24. At this point, the second staged firing pattern investigation at reduced load is finished and the experimental test plan in Table 4 has been completed.

As mentioned previously the test plan in Table 4 was abbreviated for the sake of clarity to demonstrate the procedures and techniques involved in conducting a NO_x emission reduction program. The principles employed are applicable to and may be used to conduct an expanded more detailed program. Appendix A provides examples of more extensive test programs which may be used in planning specific NO_x emission reduction test programs.

7.4 Analyzing the Results

As indicated in the previous sections, Table 4 not only outlines a suggested experimental test plan to be conducted sequentially in the order of the test plan numbers, but the plan can also be used to serve the dual purpose of recording the results of each test as the data becomes available. A brief study of the test plan after completion of the test program, or as the tests progress, gives an indication of which combustion mode is most effective in suppressing NO_x emissions. Also an insight may be gained from the data on other operating modes which might bear further investigation.

For example, referring to the first four tests in Table 4 conducted under baseline operation with all burners in service, it can be seen that test No. 2, conducted at low excess air with burner registers set at 60% open results in lowest NO_x emissions of 491 ppm. This is approximately 15% lower than baseline operation at normal air of 557 ppm in test No. 1 under the same operating conditions. Results of these four tests also show that closing the burner registers to 20% open (test Nos. 3 and 4) is less effective than with register settings of 60% open. With only these data available, one would be inclined to believe that closing the burner registers is the wrong way to go. Also one could speculate that register settings greater than 60% open might result in even lower emissions. Additional tests with different burner register settings could, obviously, be run to optimize NO_x emissions at the stated conditions but these would not provide the complete answer.

If staged firing combustion modifications are then investigated as in test Nos. 5 through 12, it can be seen that NO_x emissions may be reduced to 345 ppm (test No. 12), a reduction from baseline operation of 40 percent. It may also be noted that these lower emissions can be achieved with burner register settings at 20% open in the active burners. Reducing the air supplied to the active burners decreases the stoichiometric air ratio in these burners and forces more air to burners A_1 and A_4 (registers 100% open) used as air ports. Thus, under staged firing conditions, closed down register settings on the active burners gives better emission reduction performance, which is contrary to what one might expect judging from the data obtained in test Nos. 1 through 4.

Tests at reduced load (test Nos. 15 and 24) provide a similar pattern of results as those conducted at full load except that emissions are generally lower due to the lower load and staged firing pattern S_4. With four burners (A_1, A_2, A_3 and A_4) used as overfire air ports, greater NO_x reduction is achieved. For instance, test No. 13 at baseline conditions with registers at 60% open and all burners in service produces NO_x emissions of 629 ppm at normal air levels. Staged firing test No. 18 at low excess air with burners A_1, A_2, A_3 and A_4 used as overfire air ports and active burner registers set at 20% open, reduces NO_x down to 297 ppm. This is a reduction of almost 53 percent over baseline conditions and represents the lowest emissions obtained of the firing patterns investigated in the example.

To better understand the results achieved it is also helpful to analyze the data statistically and plot the least squares regression lines fitted to the data points corresponding to the various firing patterns. Examples of this type of analysis are given in Appendix A.

The step-by-step procedures outlined and discussed in the above examples should enable the experienced boiler operator to plan, set up and execute his own NO_x emission and efficiency optimization test program. Once the test program has been completed, the data tabulated and analyzed, and the optimum combustion modes established for NO_x reduction, tests may be repeated at these operating modes and fly-ash samples obtained in accordance with established procedures so that carbon loss data (% carbon on fly-ash) may be obtained. With these data in hand, boiler efficiency calculations can be made. It is possible that excess air levels that are too low may result in lower boiler efficiency due to increased carbon loss with some operating modes. If this happens, excess air levels should be increased and further data taken at the same operating mode to bracket or optimize efficiency, perhaps at the expense of a compromise in NO_x emissions. However, if the 200 ppm maximum CO level is generally observed for the test involved, experience shows that boiler efficiency should not be impaired when operating under "low NO_x" emission conditions.

7.5 Translating Optimized NO_x Emission Into Operating Procedures

At this point all of the tests have been run, the data have been tabulated and analyzed, and any additional tests required to further define optimum combustion modes for NO_x reduction have been completed. The problem now is to translate the test data into meaningful operating procedures for the boiler operators so the boiler may be operated over its normal range under low NO_x emission conditions. Normally, existing boilers are exempt from NO_x

New Source Performance Standards (NSPS); these standards applying only to new boilers designed and built to meet NSPS after December 23, 1971, or subsequent NSPS revisions. On new NSPS boilers, operating procedures would be established by the boiler manufacturer's engineers in cooperation with utility personnel in order to ensure compliance with air pollution regulations and the boiler manufacturer's guarantee. In other cases, where utilities may desire to operate existing boilers under low NO_x conditions, operating procedures must be established by the utility personnel after the low NO_x emission test program has been completed.

For example, using the data developed in the simplified test plan shown in Table 4, one of the major operating parameters of concern to the operator would be load and load range. In the test program it was demonstrated that full load could be developed either with all burners in service or with a maximum of two burners out of service (using the burners as air ports) but tests were only run at the 125 MW, full load rating. It was further determined that a maximum of 110 MW (reduced load) could be produced with four burners out of service. Between 110 and 125 MW, therefore, a choice can be made between using all burners or operating with two burners out of service (staging). Referring to Table 4, lowest NO_x emissions firing all burners (491 ppm) were achieved in test No. 2 with secondary air registers 60% open. Staging the combustion process at full load with burners A_1 and A_4 on air only, optimized NO_x emissions at 345 ppm at the 1.7 percent O_2 level (test No. 12). Consequently, from a NO_x emission standpoint, loads between 110 and 125 MW should be carried with the wing burners A_1 and A_4 used as air ports. However, the lower range of 110 MW may require a somewhat higher level of air in order not to exceed the arbitrary 200 ppm maximum CO level previously discussed. In order to properly define these operating parameters, therefore, another test should be run at 110 MW with coal shut off in the wing burners A_1 and A_4 and air 100% wide open in these two burners (20% open in active burners). Again, operating mode adjustments would be made at normal excess air levels, after which excess air would be decreased to the point where CO (in the lowest O_2 probe) would approach the 200 ppm maximum. Emission and operating parameter data would then be recorded, as before.

With these data in hand, operating parameters recorded during the tests may be used to establish procedures for low NO_x operation at loads between 110 and 125 MW. Within this load range, staged firing with burners A_1 and A_4 on air only (registers wide open) and active burner registers cramped down to 20% open (as in test No. 12) would be employed. Minimum O_2 levels of 1.7% would prevail at 125 MW possibly ranging upward to somewhat higher levels as established for operation at 110 MW. Note that these are minimum levels determined for "optimum" NO_x emissions. Realistically, some higher level of air will be necessary, effecting a compromise with NO_x emissions, in order to provide some degree of flexibility in operation. This necessary "cushion" must be established for each individual job and will be dictated by the control capabilities and the required degree of NO_x reduction. In the example, perhaps 2.0 percent O_2 would be targeted for operation at 125 MW and 2.5 percent for 110 MW to provide the required flexibility.

Other operating indicators would also be observed and established as parameters for the definition of operating conditions for the different loads. For example, in addition to O_2, windbox to furnace differential pressures recorded during the tests, may serve as additional operating guideposts. If windbox to furnace pressure differentials of 1.5 and 1.3 inches of H_2O were recorded for full load (125 MW) and 110 MW loads, respectively, operating procedures would use these minimum levels as guideposts to operation with corresponding interim levels at loads between 110 and 125 MW. Similarly, steam flow/air flow levels and other pertinent operating parameters such as, forced draft fan discharge pressure, etc., which have been recorded for individual tests, can be incorporated in the operating procedures in a like manner. In the example, operating parameters and procedures for staged firing (A_1 and A_4 burners used as air ports) for boiler loads of 110 MW through 125 MW, respectively, would consist of air levels ranging between 2.5 and 2.0 percent O_2; windbox to furnace differential pressures ranging from 1.5 to 1.3 inches of H_2O minimum; forced draft fan discharge pressure, e.g., varying from 25 to 24 inches of H_2O maximum and corresponding levels of steam flow and air flow recorded at these loads during the tests. Thus the operator is provided with a simplified number of important guidepost parameters delineating the type of operation required for low NO_x emissions.

For loads below 110 MW, a similar approach would be used in establishing operating procedures. In the example in Table 4, it may be seen that staged firing pattern with the top row of burners (A_1, A_2, A_3, and A_4) used as air ports (air wide open) and registers on active burners adjusted to 20% open, gave lowest NO_x emissions, i.e., 297 ppm at 2.7% O_2 (test No. 18). These emissions were achieved at 110 MW boiler load and no data exist for lower load operation. Accordingly, another test or tests should be run to establish operating conditions at minimum load for this combustion mode with the top row of burners out of service. In a fashion similar to that described before with the boiler operating at 110 MW and normal air levels, all burners in service, shut off the coal flow in burners A_1, A_2, A_3 and A_4 and open the registers to the wide open position. Re-adjust registers on the 12 active burners to 20% open. Decrease boiler load to a comfortable minimum capability with 12 burners in service. Decrease excess air to minimum values (200 ppm CO maximum) and record emission and operating data. Note where a wide load range spread is encountered, intermediate loads should be run to define operating parameters more closely. Using these data, pick out the important operating parameters, such as, load, combustion mode, O_2 level, minimum windbox to furnace pressure differential, forced draft fan discharge pressure, steam flow, air flow, etc., and incorporate these data into the operating procedures for these loads.

Pertinent operating parameters for the simplified experimental test plan example (Table 4), therefore, might appear as shown in Table 5 below, which contains the fundamental basic ideas. Table 5 may be expanded as required for more extensive test programs.

The description of the translation of NO_x emission test data into operating procedures, detailed above, is intended only as an example for those not completely familiar with boiler operation. Experienced boiler operators, such as those who undoubtedly would be intimately involved in any NO_x reduction program, should have little difficulty setting up operating parameters and procedures once the basic data is on hand.

TABLE 5

OPERATING PARAMETERS FOR LOW NO_x OPERATION

Burners Used as Overfire Air Ports*	A_1, A_4		A_1, A_2, A_3 & A_4	
Active Burner Register Position,	20% Open		20% Open	
Load, MW	125	110	110	75
O_2 Level, % Min.	2.0	2.5	2.7	3.2
Windbox/Furnace Press. Diff., in. H_2O Min.	1.5	1.3	1.3	1.4
Forced Draft Fan Discharge Press., in H_2O Min.	25	24	21	22

The appendices which follow provide more detailed and general background information helpful to anyone conducting a NO_x emission reduction program. For example, two comprehensive test plans are included in Appendix A for larger, more complicated boilers. One of these is for a 300 MW front wall fired unit (also applicable to horizontally opposed firing) and the other for an 800 MW tangentially fired boiler equipped with overfire air ports for NO_x control. Coal quality is discussed in Appendix B from the viewpoint of the boiler operator and potential effects on the NO_x emission reduction program. An understanding of the parameters affecting NO_x formation is offered in Appendix C which discusses the fundamentals of the formation of combustion generated pollutants with special emphasis on pulverized coal firing. Similarly, Appendix D provides helpful background information on the significance and fundamentals of pollutant measurements. Finally, Appendix E discusses the need for optimization of boiler efficiency from the relationship of the NO_x reduction program.

APPENDIX A

COMPREHENSIVE FIELD TEST PROGRAMS FOR NO_x EMISSION REDUCTION ON LARGE BOILERS

Section 7 covered the essential, underlying procedures employed in planning and carrying out a NO_x emission reduction program on a relatively small, pulverized coal fired, utility boiler. Basic, fundamental principles were illustrated using a simplified, abbreviated test plan example deliberately kept simple in order to avoid confusion. The basic procedures covered in detail in Section 7 are the same as would be employed in more extensive NO_x emission reduction test programs for larger boilers of more complicated designs. The fundamental ABC procedures discussed in Section 7, therefore, must be thoroughly understood, otherwise undertaking a more comprehensive NO_x reduction program would be futile.

In this appendix, examples of more comprehensive field test programs are given for two larger boilers of more complicated design. The first is a 300 MW, front wall fired, twin furnace boiler and the second an 800 MW tangentially fired boiler with tilting burners for steam temperature control and overfire air ports for the control of NO_x emissions. The salient features of each boiler design are considered and incorporated in the test programs so that the effects on NO_x emissions may be fully explored. These examples are representative of the types of boilers and design features encountered in modern utility power plants and the experimental test programs may be used as a guideline in formulating specific NO_x emission reduction programs tailored to individual needs.

Test Variables - Front Wall Fired Boiler

One of the first steps in the approach to a successful NO_x emission reduction program is to develop a test program plan. Operating variables (which are specific for each boiler) should be reviewed for inclusion in the experimental program. This is best illustrated by the example in Table A-1 showing a plan for a 300 MW, twin furnace, front wall fired boiler, firing pulverized coal, in 24 burners; twelve burners in each furnace, three rows high and four across. Operating variables included in the plan are:

Load - High (L_1), medium (L_2), and low (L_3).
Excess Air - High or normal (A_1) and low (A_2).
Staging - S_1, baseline (normal fitting).
- S_2, biased fired (firing minimum coal in the top burners and maximum in the lower burners).
- S_3, staged, top burners used as overfire air ports (air only).
- S_4, baseline (normal firing for low load) top burners out of service (air and coal off).

TABLE A-1. TEST PROGRAM PLAN
300 MW BOILER-FRONT WALL FIRED

Burner Staging Patterns	Air Register Settings	L_1 - (300 MW)		L_2 - (200 MW) (Max. Load-1 Mill Off)		L_3 - (150 MW)	
		A_1 Normal Excess Air	A_2 Low Excess Air	A_1 Normal Excess Air	A_2 Low Excess Air	A_1 Normal Excess Air	A_2 Low Excess Air
S_1 Base (Normal Firing)	R_1 Normal 70% Open	(1) 3.9% 900	(2) 1.9% 746	(11) 5.9% 739	(12) 3.15% 663		
	R_2 Closed Down 40% Open	(5) 3.9% 936	(6) 1.95% 675	(17) 5.7% 740	(18) 3.5% 735		
S_2 Biased Firing (Top Burners Fuel Lean)	R_1 Normal 70% Open	(3) 3.2% 805	(4) 1.35% 600	(13)	(14)		
	R_2 Closed Down 40% Open	(7) 3.9% 758	(8) 1.8% 570	(15)	(16)		
S_3 Staged Firing (Top Burners Air Only	R_1 Normal 70% Open (2)			(9) 6.8% 500	(10) 3.3% 213	(25) 7.0% 448	(26) 4.3% 222
	R_2 Closed Down 40% Open			(27) 6.6% 557	(28) 3.1% 237	(29) 8.0% 547	(30) 4.5% 314
	R_3 Closed Down Ignite Position			(19) 6.3% 661	(20) 2.3% 398		
S_4 Base (Top Burners Air and Coal Off	R_1 Normal 70% Open			(21)	(22) 3.2% 609	(24) 6.6% 590	(23) 5.0% 506 4.0% 465

(1) Numbers in parenthesis are test numbers. Figures are O_2 values in percent and NO_x in ppm (3% O_2, Dry Basis).
(2) Registers on all burners set at 70%.
(3) Secondary Air Registers: Top row of burners set at 40% open, bottom and middle registers set at 70% open.
(4) Top row of burner registers set at (ignition position), bottom and middle row burners at 70% open.

Burner Registers	- R_1, normal (open) secondary air register setting 70% open.
	- R_2 (partially closed down) secondary air registers setting 40% open.
	- R_3 (closed down) secondary air registers set at the ignition position for burner start up.

Test Program Plan - Front Wall Fired Boiler

For example, following the plan in Table A-1, the operating mode for Test No. 1 is baseline (S_1) or normal operation at full load in the manner the boiler is normally fired. A set of control room and emission instrumentation readings are recorded for Test No. 1. In the example, boiler emissions average 900 ppm NO_x (at 3% O_2) with the boiler operating at an average of 3.9 percent oxygen. The first and second objectives (Steps A and B) are complete at this point, i.e., the operating mode has been established and emissions have been measured.

Step by Step Procedures - Front Wall Fired Boiler

Combustion air is now decreased to establish firing conditions for Test No. 2. This is done in small controllable steps keeping watch of O_2 and CO levels (in cases where multiple probes are used, sampling is from the probe with the lowest O_2 reading). Experience shows that background CO levels for normal operation on utility boilers average between 30 and 40 ppm. Oxygen levels will be observed to drop as the air is decreased, with very little change in CO. A point will be reached where CO levels commence to increase. Continue to slowly reduce combustion air until the CO reading (from the lowest O_2 probe) reaches a level of about 200 ppm. This point is defined as the minimum acceptable excess air level. Reducing excess air beyond this point normally will increase stack opacity to unacceptable levels. On some boilers under some operating modes, especially at low loads, it may not be possible to reach the 200 ppm CO level. Stack opacity and flame appearance observations should be made for instability as the combustion air is decreased. A good criteria for the latter is the differential pressure between the windbox and the furnace. Care should be exercised in reducing excess air below the point where the windbox/furnace pressure differential drops below 1" H_2O.

Once the minimum excess air level has been established no further changes should be made and firing conditions should be allowed to stabilize (30 minutes). A set of readings should then be taken to record operating parameters for Test No. 2. In the example (Table A-1) the average O_2 measured was 1.9% with NO_x emissions of 746 ppm and the three objectives (ABC's - Section 7.2) of the first step of the test plan for baseline operation with normal register settings have been achieved.

At this point, following the test plan, excess air is increased to normal levels prior to changing to the biased firing mode (S_2). Coal rate to the top mill or pulverizer is then decreased gradually while increasing the coal rate to the bottom mills. This is accomplished while maintaining load at a constant value. This combustion mode is an attempt at a quasi-staging pattern without taking a pulverizer out of service. Full load capability could not be maintained on this boiler with one mill off. Under these conditions, combustion will be lean in the top burner rows and rich in the bottom two burner rows thus effecting a partially staged pattern. Once conditions have stabilized, Test No. 3 data are recorded as in the previous procedure described for Test No. 1. Excess air is then decreased as described above until maximum CO levels reach 200 ppm. Data for Test No. 4 is then recorded after operating equilibrium has been established (30 min.). Referring to Table A-1, it may be seen that emissions in the example were 805 ppm NO_x at high air levels of 3.2% O_2 for Test No. 3 and 600 ppm NO_x for Test No. 4 at low excess air (1.35% O_2). Again, the ABC steps for the second phase of the test phase (Tests 3 and 4) have been achieved at this point.

In the example in Table A-1, after Test No. 4, excess air is again increased to normal levels, fuel rate is evened out on all three pulverizers and burner registers are partially closed to the R_2 position, returning to the baseline mode of operation but with the burner registers on all burners partially closed. Test data for Test No. 5 is then recorded after which combustion air is decreased to minimum values and data for Test No. 6 is recorded. Emissions for baseline operation at full load (S_1) have now been characterized in Test Nos. 1, 2, 5, and 6. It may be noted that NO_x emissions of 675 ppm are lowest for the operating mode of Test No. 6, a reduction of 25% or 225 ppm NO_x from baseline values of 900 ppm in Test No. 1.

After Test No. 6, with the secondary air registers still at position R_2 (40% open), excess air is raised to normal levels, the mills are biased as before, and data is recorded for Test No. 7. Afterwards, excess air is reduced to minimum levels and data for Test No. 8 is recorded, completing emission characterization for biased firing conditions at full load. Note that emissions in Test No. 8 have been reduced by 37% to 570 ppm NO_x. This completes the optimization of NO_x emissions at full load since this particular boiler is incapable of maintaining full load capacity with one pulverizer out of service as required for firing patterns S_3 and S_4.

The same procedure is repeated at 200 MW load for Test Nos. 11, 12, 17, and 18. Staging the firing pattern, as indicated for S_3, is now possible at this load with one mill off. With the top burners used as overfire air ports, the effect of varying the amount of overfire air is investigated by operating with maximum (Test Nos. 9 and 10), intermediate (27 and 28) and minimum (19 and 20) overfire air, respectively, by making adjustments in the burner secondary air registers as indicated on Table A-1 to vary the amount of overfire air flow. From the example in Table A-1, note that minimum NO_x emissions of 213 ppm at 3.3% O_2 are achieved in Test No. 10 with maximum overfire air flow. Note, also, that emissions increase to 398 ppm NO_x in Test No. 20 for the S_3 operating mode when the use of the top row burners as overfire air ports is practically discontinued with the top burner registers set at the ignition position.

Low load tests at 150 MW are then conducted in a similar manner as indicated in the test plan (Table A-1) for firing patterns S_3 and S_4 (test Nos. 23, 24, 25, 26, 29 and 30, respectively). At this load, staging the firing pattern (S_3) using the top row of burners as overfire air ports with burner registers open as wide as possible, R_1 (70% open), again produces lowest emissions (Test No. 26) similar to Test No. 10 at 200 MW load. Note, however, that it is not possible to reduce excess air as much (4.3% O_2) in Test No. 26 at the 150 MW load as compared to Test No. 10 (3.3% O_2) at 200 MW and NO_x emissions are correspondingly lower at the higher load, i.e., 213 ppm vs. 222 ppm.

Analyzing the Results

After the field test work has been completed, the emission data tabulated on the test program plan (Table A-1) may be plotted so as to better understand what has been achieved. Figure A-1 is a plot of ppm NO_x (3% O_2, dry basis) vs. average percent O_2 in the flue gas for each test run condition. Lines have been drawn through the data for the normal (or high) and low excess air firing points for each operating condition (boiler load, firing pattern and secondary air register setting). Referring to Figure A-1, it may be seen that all of the operating variables had a significant effect on NO_x emission levels. Baseline operation (Test No. 1) resulted in an emission level of 900 ppm NO_x. Test No. 8, under low excess air biased firing conditions, is clearly shown to produce the lowest NO_x emissions (570 ppm) at full load. The boiler should be operated in this manner if NO_x emissions are to be limited. However, if faced with stricter emission standards, consideration should be given to installing separate overfire air ports so that more effective staging patterns could be employed at full load to potentially achieve further reductions in emissions.

Figure A-1 clearly shows that staged firing (S_3) results in lowest emission levels at intermediate load (200 MW) and low load (150 MW). Test Nos. 10 and 26, respectively, under low excess air firing product NO_x emissions of 213 and 222 ppm. With separate overfire air ports it might even be possible to effect further emission reductions.

Test Program Plan-Tangentially Fired Boiler

Table A-2 shows another test program plan developed for full load firing of an 800 MW, twin furnace boiler with pulverized coal. Burners fire in a tangential pattern and can be tilted for steam temperature control. On this unit separate overfire air ports were built into the top of the windbox above the top row of burners. Sufficient pulverizer capacity was included in the design to operate the boiler at full load with one pulverizer out of service.

Operating variables to be investigated include:

Load - Full
Excess Air - Normal (A_1) and Low (A_2)

Staging - S_1, Normal firing (no overfire air)
S_2, Staged firing (top row of burners used as overfire air ports)
S_4, Staged firing (25% OFA Ports)
S_5, Staged firing (50% OFA Ports)
S_6, Staged firing (75% OFA Ports)
S_7, Staged firing (100% OFA Ports)

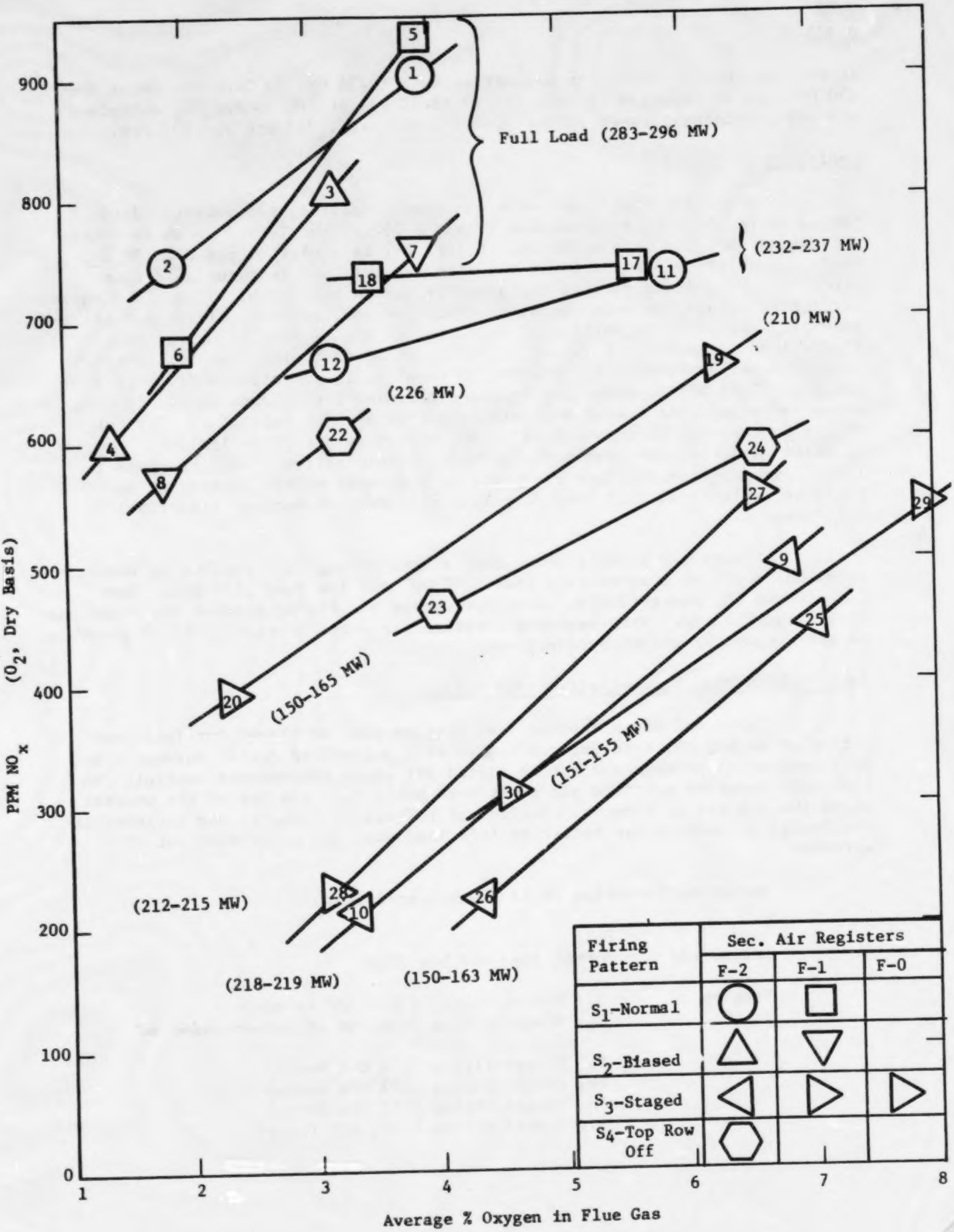


Figure A-1. 300 MW Boiler-Front Wall Fired. (PPM NO_x (3% O_2, Dry) vs Average % O_2).

TABLE A-2. TEST PROGRAM PLAN
800 MW BOILER - TANGENTIAL FIRING WITH OVERFIRE AIR
(TEST RUN NO., % OXYGEN AND PPM NO_x [3% O_2, DRY BASIS]
FULL LOAD-800 MW)

Firing Pattern / Burner Tilt	A_1 - Normal Excess Air				A_2 - Low Excess Air			
	T_1 -10° to -15°	T_2 Horizontal	T_3 $+10^\circ$ to 15°	T_4 $+25^\circ$	T_1 -10° to -15°	T_2 Horizontal	T_3 $+10^\circ$ $+15^\circ$	T_4 $+25^\circ$
S_1 Normal Firing	(3) 3.9% 332	(1) 4.9% 343	(5) 5.2% 378	(7) 4.8% 492	(4) 3.8% 314	(2) 4.2% 309	(6) 3.6% 298	(8) 3.8% 411
S_2 Top Row Air Only			(9) 5.0% 318				(10) 3.6% 259	
S_3* 25% OFA			(11) 4.0% 332				(12) 3.6% 328	
S_4* 50% OFA			(13) 3.9% 310				(14) 3.6% 326	
S_5* 75% OFA			(15) 3.8% 292				(16) 4.0% 289	
S_6* 100% OFA	(19) 5.2% 346	(21) 5.4% 329	(17) 5.2% 354 (17A) 4.6% 346		(20) 3.5% 271	(22) 3.8% 289	(18) 3.6% 282 (18A) 3.6% 288	

*Overfire air registers set at 25% open for S_3, 50% open for S_4, 75% open for S_5 and 100% for S_6.

Burner Tilt - T_1, -10 to -15° below horizontal
T_2, Horizontal
T_3, +10 to 15° above horizontal
T_4, + 25° above horizontal

Step-By-Step Procedures - Tangentially Fired Boiler

The test plan in Table A-2 was devised to first investigate emissions from the boiler fired as a normal tangentially fired boiler without using the overfire air ports. Following the test plan, set the burner tilt at horizontal (0°) with the boiler operating at full load. After operation has stabilized, record the required test data for Test No. 1 with horizontal burner tilt, normal firing pattern S_1. When this complete, reduce the combustion air to the boiler in small increments until CO levels reach 200 ppm maximum on the sampling probe with the lowest O_2. Record the data for Test No. 2. As illustrated in the example in Table A-2, NO_x emissions are reduced by about 10%, from 343 to 309 ppm between Test Nos. 1 and 2, respectively. The three objectives (ABC) for this phase of the program (T_2, S_1) are now complete.

At this point excess air is increased to normal levels and burner tilt is reset to -10 to -15 degrees (downward) from horizontal for the second operating mode to be investigated (T_1, S_1). After operation stabilizes, data are recorded for Test No. 3. Excess air is then reduced as previously discussed, until CO reaches a maximum (200 ppm) in the lowest O_2 sampling probe. Data for Test No. 4 is then recorded after operation has reached equilibrium. In the example (Table A-2) NO_x emissions decrease from 332 to 314 ppm for Test Nos. 3 and 4, respectively, and the three objectives for the second phase of the program (T_1, S_1) are complete.

Preparing for the third operating mode (T_3, S_1), excess air is again increased to normal and burner tilt is reset slowly in careful increments to the +10° to +15° position (above horizontal). Data for Test No. 5 is now taken after which excess air is again reduced to the maximum CO limitation (200 ppm) and data for Test No. 6 is recorded. Emissions of 378 and 298 are recorded for Test Nos. 5 and 6, respectively, and testing of the third operating mode is finished.

The same procedure is repeated for the fourth operating mode (T_4, S_1) burners tilted to +25° (above horizontal) and data are developed for Test Nos. 7 and 8. This completes the investigations for the four operating modes devised to show the effect of burner tilt in reducing NO_x emissions.

Attention is now given to the investigation of staging the combustion patterns in the furnace using overfire air S_2, S_3, S_4, S_5, and S_6. Tests begin with the S_2 operating mode where staging consists of using the top rows of burners as overfire air ports as might be necessary if overfire air ports were not built into the boiler. Following Test No. 8, the burner tilt is reset slowly to the +10° to +15° above horizontal from the +25° position. After superheat and reheat steam temperatures are stabilized, excess air is once again increased to normal. The top row pulverizer is then slowly taken out of service shutting coal off to the top burners while increasing coal flow in the remaining pulverizers and burners to maintain constant load. Registers on the top burners are not closed but left open as if the burners were in service. Overfire air ports, as in all previous tests, are left closed. Once boiler operation has equilibrated after making these changes, the test data are recorded for Test No. 9, operating mode T_3, S_2. Excess air is then slowly decreased until the 200 ppm max. CO level (in the probe with the lowest O_2) is reached and the test data are recorded for Test No. 10. Referring to the example in Table A-1, it may be noted that NO_x emissions are reduced from 318 to 259 ppm for Test Nos. 9 and 10, respectively. This completes operating mode T_3, S_2 characterization.

The next phase of testing concerns the investigation of the use of the built-in overfire air ports in suppressing NO_x emissions. After Test No. 10 is complete, excess air is increased to normal and the top row pulverizer and burners are put back into service in the reverse manner to that described above. The overfire air dampers are then carefully opened one by one to the 25% open position while carefully observing combustion conditions and panel board instrumentation. It is recommended that one or two dampers be opened at a time allowing sufficient time between opening the next set of dampers for operation to stabilize so that abrupt upsets do not occur. After all overfire ports are opened 25%, boiler operation should be allowed to stabilize and a set of readings should then be recorded for Test No. 11, operating mode T_3, S_3. Afterwards, excess air should be slowly decreased to minimum (200 ppm maximum CO) and another set of readings taken for Test No. 12. In the Table A-1 example, NO_x emissions are reduced from 332 to 328 ppm for Test Nos. 11 and 12, respectively, and conditions for operating mode T_3, S_3 are complete.

This procedure is repeated for operating modes T_3, S_4; T_3, S5; and T_3, S_6 respectively. However, since overfire air ports would normally be used in the wide open position, the effect of burner tilt with 100% OFA would again be investigated as in modes T_1, S_6; T_2, S_6; T_3, S_6; and T_4, S_6. The same procedures as at the start of the test would be repeated but, this time, the overfire air ports would be used (100% open) rather than using the top row of burners as overfire air ports.

The test program plan discussed concentrated solely on investigations of NO_x emission reduction techniques under full load or rated capacity conditions. A similar program plan could be developed for intermediate and low load operation. The techniques and procedures, however, are the same as described above and will not be repeated here.

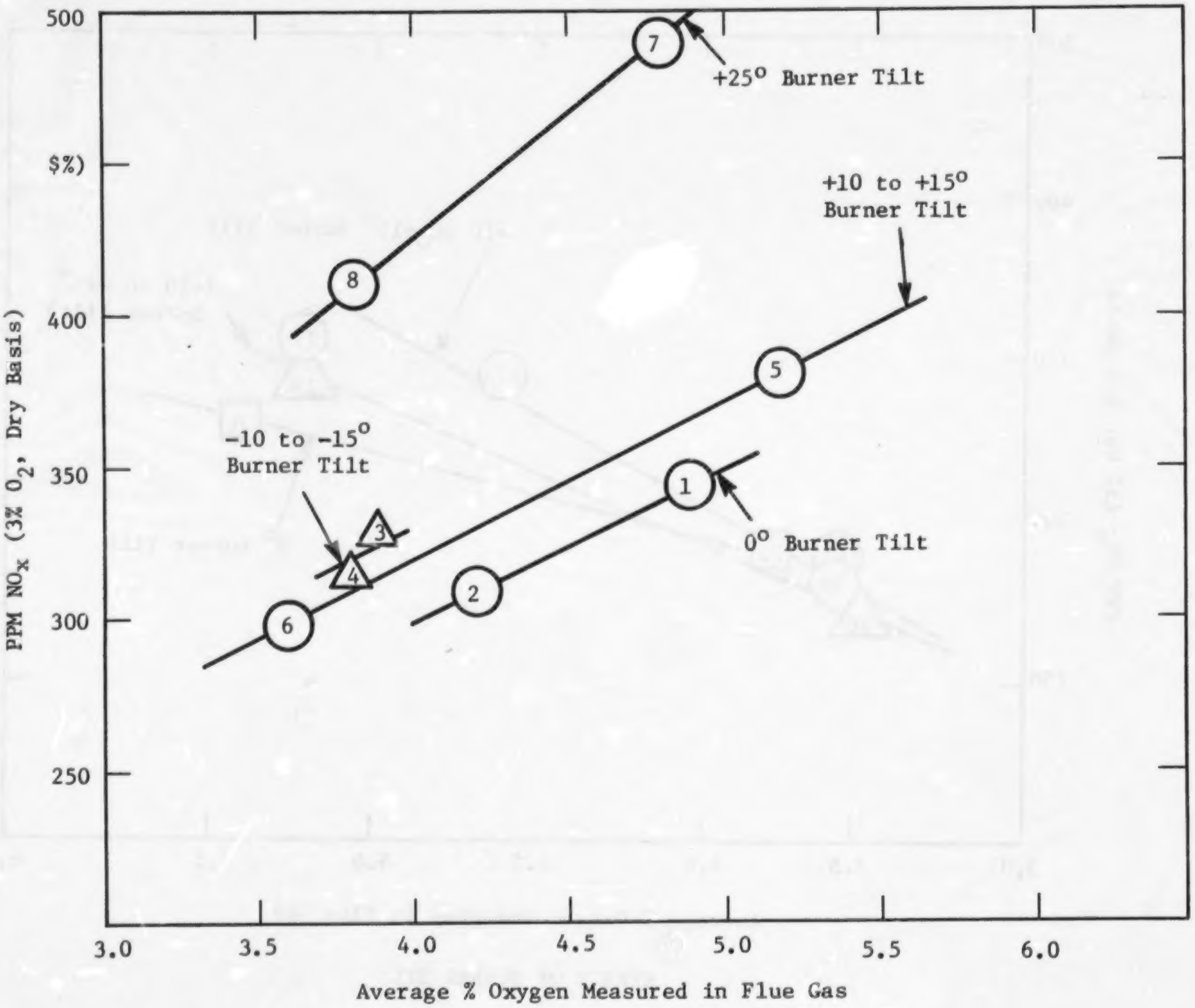
Analyzing the Results

Once the test program plan has been completed, it is helpful to plot the average emission data for each test to better understand the results. The emission data tabulated for the test plan program example in Table A-1 are plotted in Figures A-2, A-3, A-4 and A-5. The effect of burner tilt on NO_x emissions for full load, normal firing (no staging, overfire air ports closed) is shown in Figure A-2 for the S_2 operating mode. Clearly it may be seen that the horizontal position (0° tilt) produces minimum NO_x emissions. With tilt at -10 to -15° downward emissions are somewhat higher than the horizontal position due to the concentration of heat in the bottom of the furnace. Burner tilt of +25° upwards has no beneficial effect on NO_x as there is minimum separation of overfire, second stage air with first stage combustion.

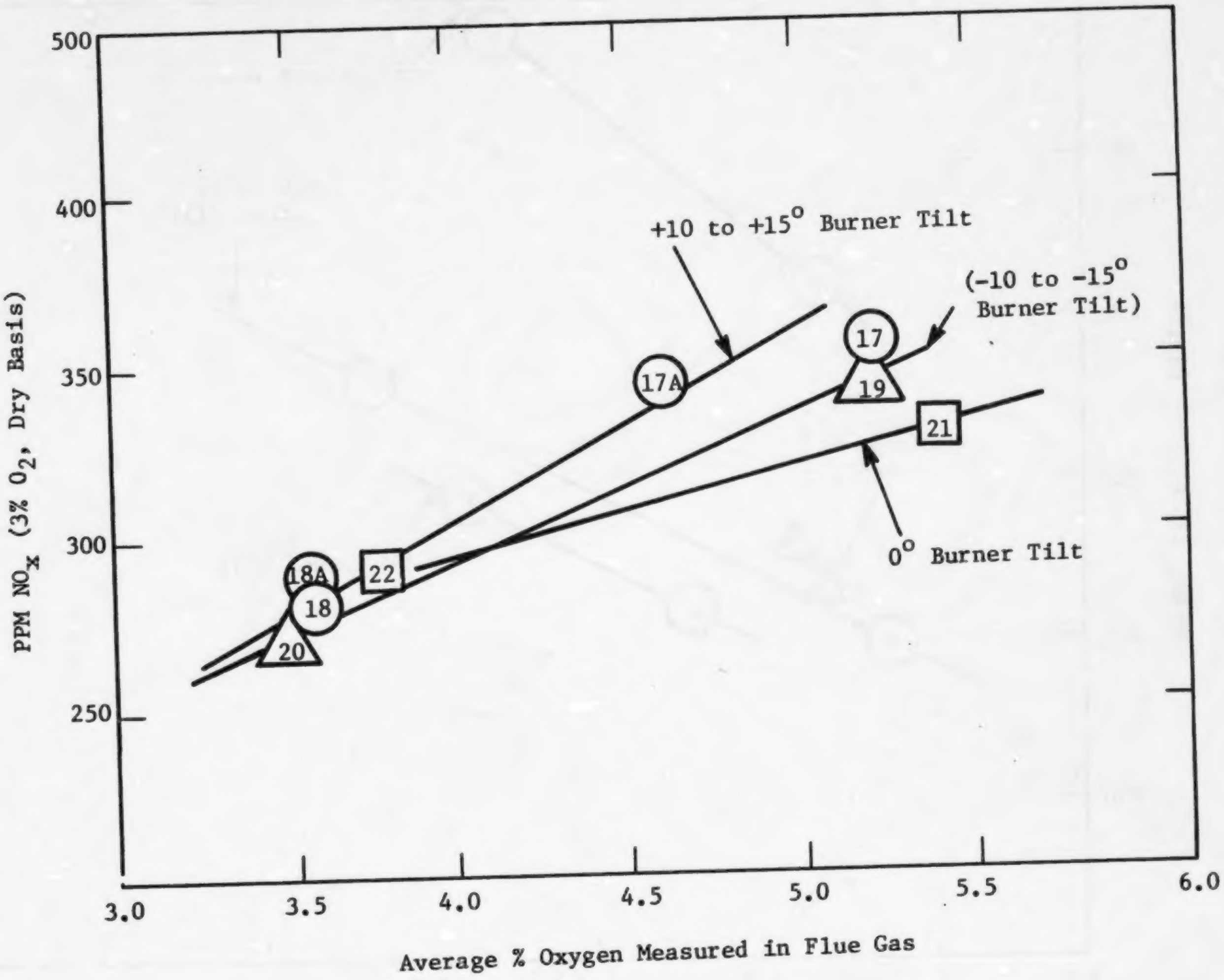
The effect of burner tilt with staged firing and overfire air ports 100% open is shown in Figure A-3, S_7 operating mode. Horizontal burner tilt is again shown to result in lower NO_x emissions at higher excess air levels. At low excess air, however, there is little to choose from with respect to the effect of burner tilt on NO_x emissions. Any burner tilt appears to produce about the same NO_x emissions at these levels of excess air.

Figure A-4 is a plot of ppm NO_x vs. percent oxygen for the S_2, S_3, S_4, and S_5 staged firing operating modes. The line labeled S_6 from Figure A-3 (+10 to +15° tilt) was drawn on Figure A-4 for comparison purposes. Short lines parallel to the S_6 line were drawn through the averaged data for S_3, S_4, and S_5 test runs. Lowest NO_x emissions resulted from test Nos. 9 and 10 (operating mode S_2) operating with the top row of burners as overfire air ports with the top pulverizer shutoff. The beneficial effect of increasing overfire air register openings from 25% (S_3) to 50% (S_4) and then to 75% (S_5) is apparent in Figure A-4. The effect of changing overfire air register settings is more dramatically shown in the plot in Figure A-5. Only test runs conducted with approximately equal excess air levels (3.6 to 4.0% O_2) and burners tilted at T_3 (+10° to +15°) are shown on Figure A-5 so the effect of overfire air damper settings on NO_x emission levels can be seen directly.

In summary, lowest NO_x emissions occur on this boiler at normal excess air levels when operating with the burners firing horizontally (0° tilt). At low excess air levels, burner tilt position has little or no effect on NO_x emissions. When staging the combustion process, increasing the air flow through the overfire air ports, as might be expected, has a corresponding decreasing effect on NO_x emissions reaching a minimum with maximum air flow. This may be observed in Figures A-4 and A-5. Lowest NO_x emissions, however, resulted when staging the combustion pattern using the top row of burners as overfire air ports (Figure A-4).

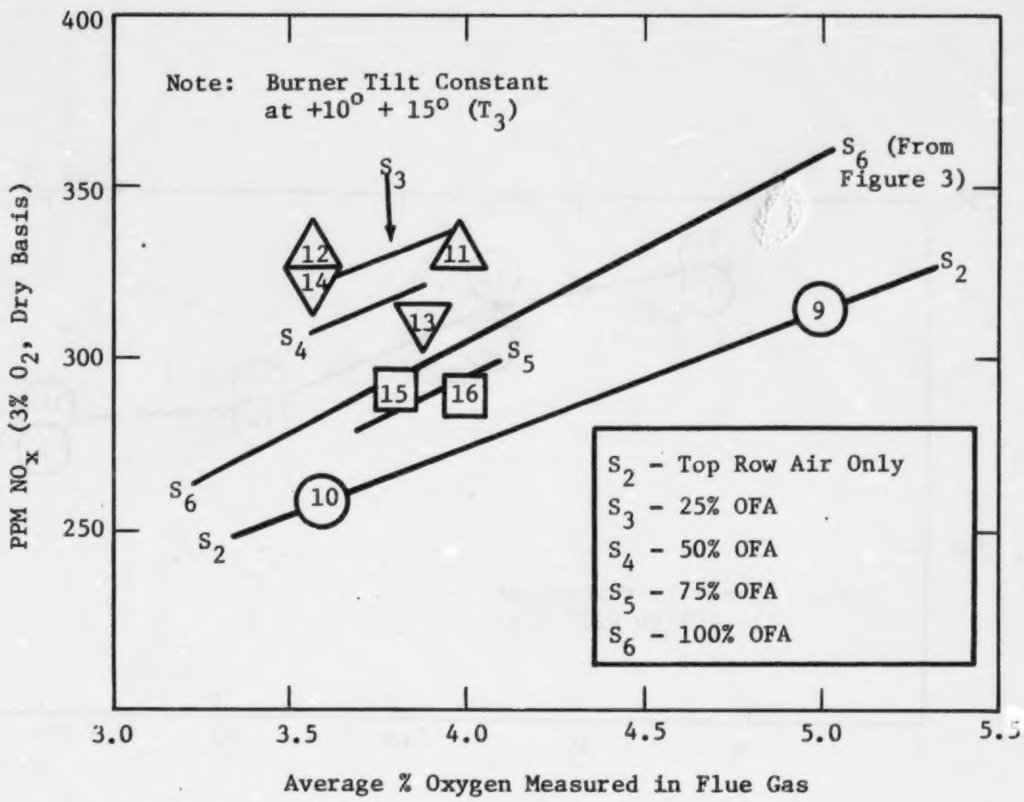


EFFECT OF BURNER TILT
Figure A-2. 800 MW Boiler-Tangential Firing
Full Load, Normal Firing.



EFFECT OF BURNER TILT

Figure A-3. 800 MW Boiler-Tangential Firing Staged Firing-Overfire Air Dampers 100% Open.



EFFECT OF OVERFIRE AIR

Figure A-4. 800 MW Boiler-Tangential Firing Full Load-Staged Firing.

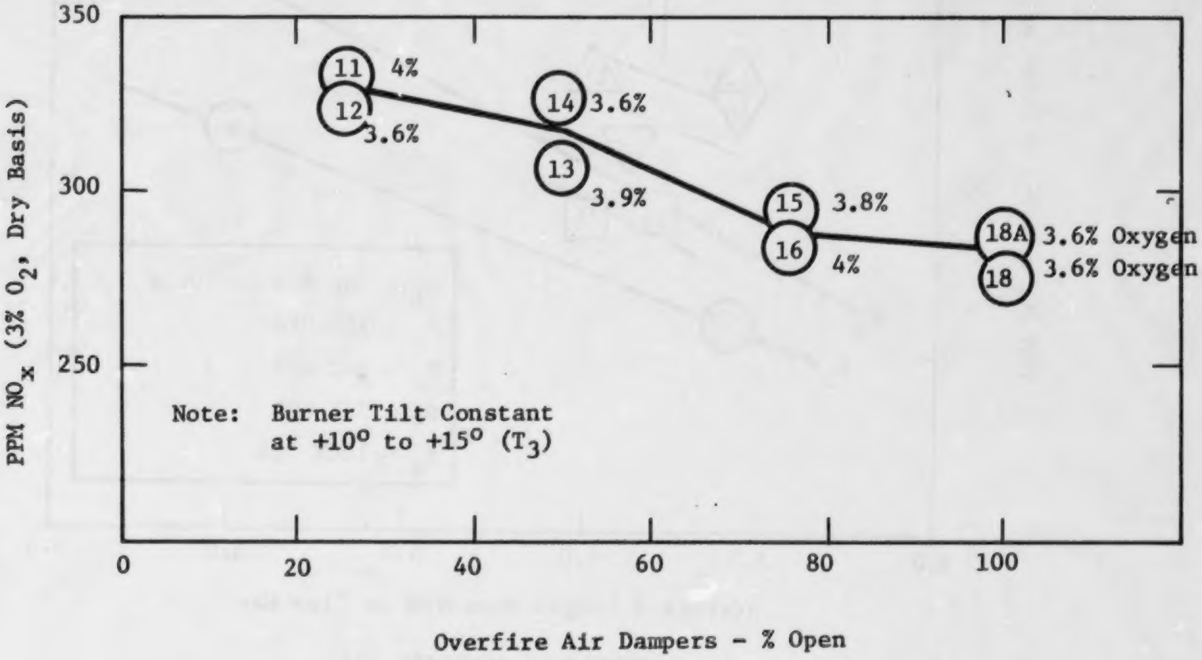


Figure A-5. 800 MW Boiler-Tangential Firing
Effect of Overfire Air Dampers on NO_x Emissions
Full Load-Staged Firing

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APPENDIX B

COAL CHARACTERISTICS

Although coals have been classified or ranked in a number of different ways, from the standpoint of the power plant operator it is generally sufficient to know that coals are ranked in the following broad categories:

Anthracite
Bituminous
Subbituminous
Lignite

It is the operator's job to cope with the burning of the coal which is supplied to the plant and it is only when operating problems develop, such as slagging, fouling, handling difficulties, etc., does he become concerned with coal supply matters. Even then the decision made generally involves a switch to a different quality coal within the above broad classification ranks. Only when new plants are proposed does the potential exist for the operator to be consulted concerning major changes in coal supplies. The above classification then fails to closely define rank and the need for further definition of boundary lines becomes important. The American Society for Testing Materials has developed a classification system which is probably referred to most frequently because it provides a clear definition of coal ranking. The ASTM information is provided in Table B-1 and classifies coals by rank according to the degree of metamorphism or progressive alteration in the natural series of coals from lignite to anthracite. Criteria are fixed carbon, volatile matter and calorific value on a mineral-matter-free, fixed carbon and volatile matter basis. Note that higher rank coals are classified on a dry, mineral-matter-free basis while lower rank coals are classified on a moist, mineral-matter-free calorific value basis.

Although the ASTM classification of coal provides more information on the broad ranking of coals, the power plant operator needs more detail regarding coal quality. Table B-2, which lists the analyses of various coals classified according to rank, as defined by ASTM Standards, together with wood and peat as representing the earliest stages of transformation of vegetal matter through wood and peat to lignite, provides additional coal quality information helpful to the boiler operator.

Coal Analysis

Coal quality may be defined or expressed in several ways through various tests and methods of analyses. The proximate analysis provides useful information on principal characteristics while the ultimate analysis gives details of the exact chemical analysis of the coal without reference to the physical form in which the compounds appear. Broadly speaking, the proximate analysis provides the power plant operator with information to judge the combustion of the coal in his furnace. Details of the ultimate analysis are required for combustion calculations.

TABLE B-1. CLASSIFICATION OF COALS BY RANK[a]

Class	Group	Fixed carbon limits, % (Dry, mineral-matter-free basis)		Volatile matter limits, % (Dry, mineral-matter-free basis)		Calorific value limits, Btu/lb (Moist[b] mineral-matter free basis)		Agglomerating Character
		Equal or greater than	Less than	Greater than	Equal or less than	Equal or greater than	Less than	
I Anthracitic	1 Meta-anthracite	98	--	-	2	--	--	Nonagglomerating
	2 Anthracite	92	98	2	8	--	--	
	3 Semianthracite[c]	86	92	8	14	--	--	
II Bituminous	1 Low volatile bituminous coal	78	86	14	22	--	--	Commonly Agglomerating[e]
	2 Medium volatile bituminous coal	69	78	22	31	--	--	
	3 High volatile A bituminous coal	--	69	31	--	14,000[d]	--	
	4 High volatile B bituminous coal	--	--	--	--	13,000[d]	14,000	
	5 High volatile C bituminous coal	--	--	--	--	11,500 10,500	13,000 11,500	Agglomerating
III Subbituminous	1 Subbituminous A coal	--	--	--	--	10,500	11,500	Nonagglomerating
	2 Subbituminous B coal	--	--	--	--	9,500	10,500	
	3 Subbituminous C coal	--	--	--	--	8,300	9,500	
IV Lignite	1 Lignite A	--	--	--	--	6,300	8,300	
	2 Lignite B	--	--	--	--	--	6,300	

a - This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 48 percent dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter free British thermal units per pound.

b - Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

c - If agglomerating, classify in low-volatile group of the bituminous class.

d - Coals having 69 percent or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

e - It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class and there are notable exceptions in high volatile C bituminous group.

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TABLE B-2. PROGRESSIVE STAGES OF TRANSFORMATION OF VEGETAL MATTER INTO COAL

Fuel Classification	Locality	Moisture (as-received)	Analysis on dry basis								Heating value Btu (dry basis)
			Proximate			Ultimate					
			V.M.	F.C.	Ash	S	H_2	C	N_2	O_2	
Wood		46.9	78.1	20.4	1.5		6.0	51.4	0.1	41.0	8835
Peat		64.3	67.3	22.7	10.0	0.4	5.3	52.2	1.8	30.0	9057
Lignite	North Dakota	36.0	40.8	38.1	12.1	1.8	4.0	64.7	1.9	15.5	11038
Lignite	Texas	33.7	44.1	44.9	11.0	0.8	4.6	64.1	1.2	18.3	11084
Subbituminous C	Wyoming	22.3	40.4	44.7	14.9	3.4	4.1	61.7	1.3	14.6	10596
Subbituminous B	Wyoming	15.3	39.7	53.6	6.7	2.7	5.2	67.3	1.9	16.2	12096
Subbituminous A	Wyoming	12.8	39.0	55.2	5.8	0.4	5.2	73.1	0.9	14.6	12902
Bituminous High Volatile C	Colorado	12.0	38.9	53.9	7.2	0.6	5.0	73.1	1.5	12.6	13063
Bituminous High Volatile B	Illinois	8.6	35.4	56.2	8.4	1.8	4.8	74.6	1.5	8.9	13388
Bituminous High Volatile A	Pennsylvania	1.4	34.3	59.2	6.5	1.3	5.2	79.5	1.4	6.1	14396
Bituminous Medium Volatile	West Virginia	3.4	22.2	74.9	2.9	0.6	4.9	86.4	1.6	3.6	15178
Bituminous Volatile	West Virginia	3.6	16.0	79.1	4.9	0.8	4.8	85.4	1.5	2.6	15000
Semianthracite	Arkansas	5.2	11.0	74.2	14.8	2.2	3.4	76.4	0.5	2.7	13142
Anthracite	Pennsylvania	5.4	7.4	75.9	16.7	0.8	2.6	76.8	0.8	2.3	12737
Meta-anthracite	Rhode Island	4.5	3.2	82.4	14.4	0.9	0.5	82.4	0.1	1.7	11624

V.M. - Volatile Matter
F.C. - Fixed Carbon
S - Sulfur
H_2 - Hydrogen
C - Carbon
N_2 - Nitrogen
O_2 - Oxygen

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For power plant work, as-received air dried or moisture-free analyses are generally used. Classification of coals normally are made on a moisture and ash-free and moisture and mineral-free analyses basis. The as-received analysis comes closest to the condition of the coal delivered to the power plant and compares more closely with the as-shipped or as-fired values. Loss or gain of moisture between the time of sampling and analysis depends greatly on the method of handling the sample, the type of coal, its size and weather conditions.

Coal Quality

The following discusses briefly coal quality characteristics included in the proximate and ultimate analyses of Table B-2 and their relationship and effect on combustion problems in the power plant.

Moisture

All coal contains some natural moisture - from 1% to 5% in most eastern coals, and up to 45% in some lignites. This moisture lies in the pores and forms a true part of the coal, being retained when the coal is air dried. Surface moisture, on the other hand, depends on conditions in the mine, and the weather during transit. Moisture increases shipping costs and decreases boiler efficiency through moisture losses from the boiler.

Moisture generally is determined quantitatively in two steps: air drying and oven drying. The air-dried component of the total moisture value should be reported separately, because this information is required in the design and selection of coal-handling and coal-preparation equipment. Keep in mind that it is the surface moisture that must be evaporated from anthracite and bituminous coal before pulverization to maintain high grinding efficiencies.

Volatile Matter

Volatile matter is that portion of the coal which is driven off in gaseous form when the fuel is subjected to a standardized temperature test. It consists of combustible gases, such as methane and other hydrocarbons, hydrogen and carbon monoxide, and noncombustible gases. Since the quantity of volatile matter indicates the amount of gaseous fuel present, it affects firing mechanics. It also influences furnace volume and the arrangement of heating surfaces.

Fixed Carbon

Fixed carbon consists mainly of carbon but may contain small amounts of oxygen, nitrogen, sulfur and hydrogen not driven off with the volatile matter. Essentially it is the combustible residue remaining after the volatile matter distills off. The hardness of the fixed carbon is an indication of the caking properties of the coal which can be important in the selection of fuel handling equipment.

Ash

Ash is an impurity that increases shipping and fuel handling costs. It is that portion of the coal left over after combustion. It deposits on furnace surfaces causing slagging and carries over into superheater, reheater, economizer, and air heaters contributing to fouling problems. Portions escape with the flue gases which must be collected in precipitators or dust collectors. Part of the ash and slag drops to the bottom of the furnace into the ash hopper, requiring complicated handling systems for removal. It is important to know the amount and character of ash before coal is purchased to avoid or to minimize some of the problems mentioned above. Ash also tends to have an effect on the combustion process, resulting in increased carbon carried to the ash pit or to the precipitator.

Sulfur

Sulfur is an undesirable element contained in raw coal in amounts as high as 8 percent. The effects of burning sulfur result in many nuisance side effects in the boiler not the least of which is the emission of sulfur oxides to the atmosphere which, under present regulations, requires installation of expensive sulfur removal systems. Corrosion of furnace tubes, stacks, and cold end sections of air heaters, has also been directly attributable to sulfur. Reliable data on fuel sulfur content is important in negotiating equitable fuel contracts.

Organic sulfur (combined with the coal substance), pyritic sulfur (combined in the form of marcasite or with iron in the form of mineral pyrite) and sulfate sulfur (calcium or iron sulfate) are the three forms of sulfur contained in raw coal. Organic sulfur and the finely divided pyrites are the forms of sulfur considered to be non-removable economically under present day technology. Technology exists, however, for the removal of pyritic sulfur by washing the coal. Sulfate sulfur is not an important problem, being present in coal in minute amounts. Aside from its nuisance value, the calorific heating value of sulfur is low, making it undesirable from an efficiency standpoint.

Nitrogen

Until recently, when emphasis was placed on pollution control, little attention was given to the nitrogen content of raw coal. Experience has shown that NO_x emissions occur from two sources (1) fixation of the nitrogen in the combustion air (termed "thermal NO_x") and (2) from nitrogen in the fuel (termed "fuel NO_x"). Thermal NO_x emissions can be greatly reduced as discussed in this guideline but control of "fuel NO_x" formation while affected by certain combustion modifications is not as easy to control. Therefore, fuel nitrogen content is of importance to the control of NO_x emissions. Unfortunately, economic processes do not exist in today's technology for the removal or reduction of fuel nitrogen. Nitrogen content of coals generally used in coal fired power plants, as indicated in Table B-2, ranges between 0.8 and 1.9 percent for bituminous, subbituminous, and lignite fuels. Coal selection solely on the basis of nitrogen content does not appear to be feasible.

Heating Value

The calorific, or heating value, of a fuel is of utmost importance in the purchase of coal since BTU's or energy is what is actually being purchased. From Table B-2 it may be seen that the higher ash and oxygen contents of the lignites and some subbituminous coals adversely affect the heating value of the coal. The adverse effects of high ash content have already been mentioned and it should be recognized that high oxygen content has an equal deleterious effect on heating value. The price of the coal should reflect these undesirable qualities.

It should also be recognized that when a coal sample is burned in a bomb-type calorimeter filled with oxygen under pressure, the fuel's higher-heating value is measured. The latent heat of water vapor contained in the combustion products is lost in the stack gas since the water vapor in the flue gas is not cooled below its dewpoint during normal boiler operation. Thus the latent heat is not available for making steam and it is often subtracted from the high-heating value to give the net or lower-heating value.

APPENDIX C

FORMATION OF COMBUSTION-GENERATED POLLUTANTS

This appendix section has been designed to provide fundamental background information on the formation of combustion-generated pollutants. It emphasizes those pollutants most closely identified with the combustion of pulverized coal. This section also provides some background on why pollutants form and an indication of how to minimize pollutant formation through combustion modifications.

This section begins by discussion mechanisms of coal-fired combustion. Discussed subsequently are the formation routes for pollutant emissions of:

- Nitrogen oxides
- Sulfur oxides
- Particulates
- Hydrocarbons
- Carbon monoxide

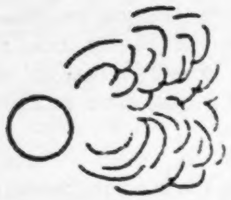
Coal Combustion Mechanisms

The combustion of coal has been considered to occur in three regimes: totally detached flame, attached diffusion flame and char burn-out. These will be discussed with reference to a pulverized coal particle fired in suspension. The three cases are illustrated in Figure C-1.

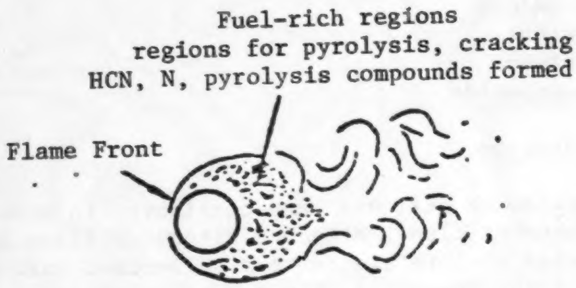
The first regime occurs during periods of rapid volatilization of the coal particle and large relative velocities between the particle and the surrounding gases. Combustion occurs in the wake trailing the particle where the fuel and oxidizer have the opportunity to mix, at least partially, before combustion starts. This regime will be found in coal firing only when the rate of heating is high causing the particle to release large quantities of volatiles explosively, or when the velocity of volatiles escaping from the particle is high. The volatilized species will be combusted far from the fast travelling particle.

The second regime, the attached diffusion flame, occurs when the rate of vaporization is slow enough to allow a flame to attach itself to the particle. Here most of the combustion occurs in a thin flame sheet surrounding the particle and its wake. The reactions occurring in this diffusion flame sheet are quite different from those occurring in the case of the totally detached flame where some premixing of air and volatiles occurs. In the case of the attached diffusion flame, there are hot, fuel-rich regions where precombustion pyrolysis can occur. In such a flame front the "fuel" can be considered to be the products of pyrolysis.

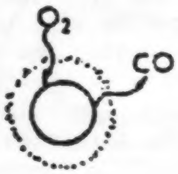
In the third regime, char burn-out, the volatile constituents initially present in the coal particle are depleted and the remaining heavy ends are pyrolyzed and convereted into a char. As the volatiles are deleted, the flame front approaches the particle until oxygen molecules can attack



A. Totally Detached Flame. Rapid mixing, rapid volatilization


Fuel-rich regions
regions for pyrolysis, cracking
HCN, N, pyrolysis compounds formed
Flame Front

B. Attached, Diffusion Flame. Pyrolysis occurs in fuel-rich region char is being formed



C. Char Burn-Out. Surface combustion occurs when volatiles have been driven out. CO formed as a result of surface reaction of carbon and O_2. This CO burns externally to the solid particle in a diffusion flame.

Figure C-1. Three regimes of coal particle combustion.

the char directly. In burn-out, carbon is converted at the surface to CO and nitrogen probably winds up forming NO. In the flame surrounding the char particle, the CO will burn to completion and the NO may possibly be further converted to other products.

Nitrogen Oxides

Flue gas from fossil fuel fired utility boilers usually contains concentrations of nitric oxide (NO) and nitrogen dioxide (NO_2) of 1500 ppm or less. NO and NO_2 are collectively referred to as NO_x. At high temperatures equilibrium favors the formation of NO, so essentially all of the nitrogen oxides in the firebox of a combustion unit are in that form. Lower temperatures favor the oxidation of NO to NO_2, but the residence time of flue gas in the unit at low temperature is too short for this reaction to occur to any great extent. So most of the nitrogen oxides (>90%) in the flue gas are in the form of NO. However, after the NO is emitted to the atmosphere there will be a much longer residence time in which the oxidation can occur. The rate and extent of conversion of NO to NO_x depend on the amount of dilution with ambient air, temperature, sunlight, and the presence of other materials such as hydrocarbons and oxidants with which it can interact.

NO is a colorless, odorless gas which is not generally regarded as a health hazard at concentrations found in the atmosphere. Because NO is converted to NO_2 in the atmosphere, most exposure is, in fact, exposure to NO_2. Nitrogen dioxide is a yellow-brown colored gas with a pungent odor. The effects of exposure to low levels of NO_2 (e.g., <50 ppm) may take several days to develop. At higher levels such as 60-150 ppm, exposure can result in immediate respiratory system reaction such as nose and throat irritation, coughing, etc. Chronic exposure to even low concentrations can produce chronic respiratory tract irritation.

NO_x which is formed in combustion processes arises from two sources:

1. "Fixation" of atmospheric nitrogen, i.e., the reaction of N_2 from the atmosphere with O_2 under the intense conditions of combustion. Because of the high temperatures involved, NO_x formed via this mechanism is termed "thermal NO_x". The rate of formation of thermal NO_x is very sensitive to temperature.
2. Conversion of "fuel" nitrogen, (i.e., nitrogen atoms bound into fuel molecules) to NO_x. This is termed "fuel NO_x". Fuel NO_x formation is not significantly temperature dependent.

The NO_x formed from both sources is chemically identical and its origin can be determined only through controlled experiments.

The relative importance of the two sources depends on fuel type and nitrogen content as well as the type, size and operating conditions of the combustion unit in which the fuel is burned. In some cases thermal NO_x will constitute most or all of the NO_x emission. In other cases, fuel NO_x will be responsible for most or all of the NO_x emission.

The formation of thermal NO_x is known to proceed via a free radical mechanism. The mechanism is initiated by the rupturing of an oxygen molecule, O_2, into two oxygen radicals due to the high flame temperatures. Thus, the variables governing the amount of NO_x formed include:

- peak flame temperature (the higher it is, the greater the fraction of oxygen molecules coverted to radicals).
- residence time at elevated temperatures (favors radical formation and reaction).
- availability of excess oxygen (the more oxygen molecules present, the more oxygen radicals can be formed).

On a practical basis, NO_x formation tends to be high in combustion units in which the flame zone temperature is high. Factors which influence flame zone temperature include:

Size - flame temperatures in larger boilers are frequently higher than in smaller boilers.

Type of firing - wall-fired boilers have a hotter, more intense flame than tangentially fired boilers, where there are burners at all four corners.

Refractory - covering water tubes in the firebox with belts of refractory increases flame zone temperature.

Typically, 15 to 100% of the nitrogen contained in fuel is converted to NO_x, with the greater conversions occurring when the fuel nitrogen level is low. The fuel nitrogen compounds responsible for fuel NO_x are considered to be derivatives of such components as pyridene and quinoline which are volatilized in the high temperatures near the combustion zone, and are subsequently burned. It is believed that a substantial fraction of the NO_x resulting from coal combustion is fuel NO_x. Combustion modifications affect formation of both thermal NO_x and fuel NO_x but are less effective on the fuel NO_x portion which is not as readily controllable.

As noted above, the primary variables governing the amount of NO_x formed are the availability of excess oxygen, peak flame temperature, and the residence time available at elevated temperatures. NO_x formation can be controlled by modifying combustion conditions to minimize the values of any or all of these variables. The most common approaches include staged combustion low excess air. In extreme cases, load reduction may be legislated but this normally is not viable economically.

Combustion modifications such as flue gas recirculation and staged combustion have been used effectively on gas and oil fired utility boilers, and the latter has been demonstrated to be effective on coal-fired utility boilers. Flue gas recirculation utilizes cooled flue gas recirculated into the combustion air supply to reduce flame temperature. With staged firing, combustion is initiated with less than stoichiometric air in the first stage and is completed, possibly after some interstage cooling, with the introduction of additional air in the second stage. This method both reduces peak flame temperatures and the local availability of oxygen.

In utility boilers staged combustion is often accomplished by admitting 70-90% of stoichiometric air through the burners, with the remaining air then brought in through auxiliary ports or through burners which have been taken out of service. Staged combustion has occasionally been used in combination with flue gas recirculation to provide further NO_x reductions than can be provided by either technique individually.

Operating at low excess air levels usually serves to minimize NO_x formation by reducing the availability of oxygen, whereas running at reduced throughput and firing rates often reduces NO_x emissions by lowering peak combustion temperatures. Of these two approaches, the former has the advantage of improving combustion efficiency, while the latter may not be practical from an operating standpoint.

The formation of fuel NO_x is only slightly temperature dependent, so that staged combustion and low excess air are the only combustion approaches effective in its control. On the other hand, NO_x formed by the thermal fixation of nitrogen and oxygen in the combustion air is extremely temperature dependent and can be controlled by any or all of the combustion modification techniques. Other approaches to controlling thermal NO_x which have been investigated include lowering combustion air preheat temperatures or injecting steam or water into the combustion zone. These techniques, however, suffer from efficiency losses.

Sulfur Oxides

When coal is combusted, most of the sulfur in the coal is converted to sulfur oxides. The oxides formed are sulfur dioxide, SO_2, and sulfur trioxide, SO_3. Sulfur dioxide is a colorless, nonflammable gas which is generally regarded as being highly irritating. It can be detected by an individual by taste and smell in concentrations of 3-5 ppm. Sulfur trioxide is a vapor in the hottest zones of most combustion equipment but can condense to a mist in the cooler boiler regions or can condense after being emitted from a stack as a blue-tinted plume. SO_3 is a strongly acidic pollutant which is responsible for back end corrosion in boilers. The sum of SO_2 plus SO_3 is frequently termed SO_x. The total quantity of SO_x emitted is generally a direct function of the sulfur content of the fuel.

Typically, in the hottest sections of a boiler about 1 to 3% of SO_x will be present in the form of SO_3, although SO_2 may be oxidized to SO_3 in the ambient air and downstream of the air preheater.

If a fuel such as coal contains large quantities of ash, or if the ash constituents are basic, some SO_x will be adsorbed on the ash particles or will react with the ash constituents to form sulfates. The quantity of SO_x which is absorbed by coal ash depends upon the nature of the coal, the quantity and type of basic constituents in the coal and the firing method. In one test in which bituminous coal was fired, sulfur retention was less than 5%. In another test in which lignite was fired, sulfur retention ranged from 10 to 40%. Lignite ash is basic due to the high concentration of alkali and alkaline earth compounds it contains.

Combustion modification cannot reduce the total quantity of SO_x formed in coal firing. This is a function of the coal sulfur level and the nature of the coal which can change the quantity of SO_x converted to ash. However, the SO_3/SO_2 ratio can be varied through combustion modifications. Thus, the factors effecting SO_3 formation will be considered briefly.

Sulfur trioxide formation can occur via either "homogeneous" or "heterogeneous" pathways. The former is known to occur both in the flame and in the high temperature reaction zone in the flue gas just beyond the flame. It is this formation route which is most directly influenced by combustion modification and which will be discussed here in greater detail. The latter mechanism involves suspended fly ash and furnace deposits. The relative importance of these depend on the furnace, fuel and operating conditions.

The factors which influence homogeneous SO_3 formation are:

- excess air level
- flame temperature
- flame quench rate

Let us see why these factors are important.

High temperature SO_3 formation occurs when free radical oxygen atoms react with SO_2 converting it to SO_3. The free radical oxygen atoms are formed because of the high temperature of the flame. Up to a point, the greater the excess air level, the greater the number of free radical oxygen atoms that can be formed and consequently the greater the quantity of SO_3 formed. Thus, SO_3 formation can be minimized by minimizing the level of excess air used. This is also good for NO_x control. However, increasing excess air above a certain point (estimated to be about 30-40%) will reduce flame temperature and will thereby reduce the quantity of free radical oxygen atoms available for reaction thus lowering the quantity of SO_3 formed. However, this may result in higher levels of NO_x and will have a negative effect on efficiency. SO_3 is kinetically more stable at low than at high temperatures. Consequently, after SO_3 has formed at high temperatures, it will begin to decompose if kept at that temperature because of kinetic considerations. If it is cooled just after being formed, most will remain as SO_3. Thus, flame quench should be gradual to permit the SO_3 to decay as it will at high temperatures.

Particulates

Particulate matter and smoke can be emitted when coal is combusted, especially if the equipment is operated under maladjusted conditions. The form of particulate matter emitted from stationary combustion sources includes:

Smoke - submicrometer-size particles of carbon formed in the vapor phase during combustion.

Cenospheres (or chars) - unburned carbonaceous residues of fuel particles. May be 5 to 50-micrometer particles.

Ash - non-combustible residues of fuel. May be 5 to 10-micrometer particles, or submicrometer if the ash vaporizes and recondenses.

Size, composition and quantity are significant factors which must be considered in evaluating the importance of particulates. Small particles (< 1 micrometer) settle slowly in ambient air and reduce visibility more per unit weight than larger particles. Of particular concern are particles <15 micrometers in diameter which are termed inhalable particulates because they can be breathed into the lungs where they may produce adverse health effects.

The particulate mass produced by coal-fired power plants is significant. Electric power generation by utilities accounts for 13% of the total man-made emissions of particles in the U.S. Coal combustion accounts for 98% of particulate emissions from utilities. It is important to realize that these emissions occur after treatment by emission control devices such as electrostatic precipitators, cyclones, scrubbers and filters. Particulate control devices have an overall particle collection efficiency ranging from 80 to 99%, the last figure being for boilers firing pulverized coal with electrostatic precipitators, and the first for stoker fired boilers using mechanical collectors. Particulate control devices are generally relatively effective in the control of large particulates. The control devices are substantially less efficient for the collection of respirable or inhalable particulate. For example, efficiency of control devices in boilers firing pulverized coal amounted to 75% in one survey. Significantly, in these units, 35% of all particulates by mass were of the fine, respirable variety.

Before discussing the forms of particulate matter emitted, let us review the processes which occur to a coal as it is combusted.

The coal particle is swept into the furnace where it receives heat from the surroundings. Organic volatiles in the particle begin to evaporate. The volatiles burn instantaneously and completely. At the same time, the particle swells and forms a hollow, porous sphere. Once volatilization has ended, oxygen has access to the sphere and the carbon in it begins to burn, forming CO_2 (or CO which is oxidized to CO_2). The residue consists of inorganic ash and any uncombusted carbon.

Smoke is composed of submicrometer-size carbon particles formed in the vapor phase which surround the coal particle during the first stage of combustion. The mechanism of smoke formation is generally considered to include cracking of volatilized molecules in the zone where there is insufficient oxygen, followed by polymerization of the cracked fragments to form hydrogen deficient condensed ring structures. These collect into particles on the order of 0.1 micrometer in size. Most of the smoke particles burn out in the flame, imparting a characteristic yellow-orange color. Even small amounts of smoke by weight in the flue gas are highly visible. If 0.1 to 0.2% of the fuel forms smoke, it will appear as a dense, black cloud on leaving the stack. Mixing, combustion zone temperature, air/fuel ratio and particle size are significant determinants of the quantity of smoke emitted. Smaller particles and better mixing decrease the possibility of forming fuel-rich pockets in which smoke forms. High excess air levels permit the flame to be close to the particle minimizing the space in which cracking can occur. High combustion zone temperature favors rapid volatilization so that combustion is completed early and there is ample opportunity for smoke to be consumed.

Most of the factors which minimize smoke formation tend to favor NO_x formation since they involve short, intense flames with high, localized temperatures and good oxygen distribution in the hot zone. Thus, the problem of minimizing both smoke and NO_x emissions from fuel combustion is basically that of minimizing time-temperature history for NO_x control without increasing smoke emissions.

Cenospheres form during combustion when the volatile portion of a coal particle vaporizes, leaving a residue of carbon and ash. The carbon which remains tends to burn slowly. Thus, long residence times at high temperature with sufficient excess air reduces the emission of cenospheres. These additions are more likely to be met in a large boiler than in a small one, and large boilers have been found to emit fewer cenospheres than small boilers. Coal particle size is also a factor. The finer the particle, the greater the resulting surface to volume ratio which favors diffusion of oxygen to the surface so the cenosphere can burn out.

Ash remains after the carbonaceous matter has burned out of the cenospheres. The quantity of ash formed is directly related to the ash content of the coal. Certain elements present in coal are volatile at flame temperature. These include sodium and vanadium. Thus, these ash constituents may vaporize and recondense to form submicrometer particulates in the flue gas.

Normally the cenospheres and ash residue account for a major part of the weight of particulates emitted from coal firing. Thus they have a major effect on emission factors and their elimination would cause a significant reduction in the weight of particulate emitted. Yet, there is some question about how effective this would be as a particulate control measure. Because of their size, 10-50 micrometers, cenospheres settle out rapidly near the point of emission. However, the smaller particulates especially those below 1 micrometer probably constitute a much more important contribution to the ambient air quality and require more stringent controls.

Carbon Monoxide

The formation of carbon monoxide in the combustion process is generally associated with incomplete combustion. Carbon monoxide, CO, is a colorless, odorless toxic gas. In well-controlled combustion processes, CO emissions will generally be quite low. For example, pulverized coal combusted in utility boilers produces CO levels of approximately 30 to 40 ppm.

Lowering the excess air level below a critical value will increase CO emissions sharply, forming a "knee". Both the shape of the knee in the CO curve and the excess air level at which it occurs generally vary from boiler to boiler. These characteristics are a function of fuel type, combustion unit type and burner characteristics. The sharp rise in CO level occurs because of imperfect mixing of the fuel and air, a condition accentuated as the ideal stoichiometric fuel/air ratio is approached. Thus, partially combusted portions of coal gases on coal char do not mix well with sufficient air to complete their combustion before leaving the flame zone. In addition, quantities of fuel can bypass the normal combustion zone and mix with flue gas which does not contain sufficient oxygen for complete combustion. Under proper combustion conditions, virtually all CO formed is combusted to CO_2.

The use of CO as a combustion control parameter is increasing in the U.S. It has been used for this purpose in Europe. To control combustion, use is made of the knee. Holding CO emissions at a specified level such as 200 ppm or less should minimize excess air (low excess air firing), resulting in increased boiler efficiency and lower emissions of NO_x and SO_3.

CO emissions are generally controlled through proper combustion operating practices and combustion equipment design. Unfortunately, some combustion practices designed to reduce CO tend to raise NO_x emissions. For example, CO formation can be minimized by providing for rapid reaction rates. This means assuring rapid contact through the mixing of air and fuel, providing sufficient air for complete combustion and preheating fuel and air, all of which tend to increase NO_x. Clearly, this is a trade-off situation in which CO and NO_x emissions must be minimized.

A prime operating practice which minimizes CO formation is the effective adjustment of the fuel/air ratio. The minimum amount of air which produces acceptable CO and NO_x levels is to be used. If air well over the stoichiometric amount is used, the combustion temperature will be lowered, efficiency will decrease, and increased levels of NO_x will result.

Hydrocarbons

Hydrocarbons consist of uncombusted or partially combusted carbon-containing vapors and gases of diverse molecular composition. The types of hydrocarbons, HC, which can be formed may vary greatly, thereby precluding broad generalizations regarding their characteristics.

The presence of HC emissions are symptomatic of incomplete combustion. Thus, hydrocarbons are produced due to poor mixing and the localized insufficient oxygen for combustion. The level of hydrocarbon emissions resulting from the combustion of pulverized coal in power plants is low, ranging from less than one ppm to ten ppm. Thus, when coal combustion is under good control, HC emissions are generally not a problem.

The procedures to follow for reducing HC emissions involve increasing the excess air level and/or improving air-fuel mixing. Generally, as excess air is reduced, CO emissions increase before HC emissions increase. Therefore, if the CO level is low, HC levels should also be low.

APPENDIX D

METHODS OF MEASURING POLLUTANTS AND OTHER COMBUSTION PRODUCT EMISSIONS

This appendix is a discussion of the fundamentals of pollutant measurement, and is divided into two primary sections. These deal with particulate emissions and gaseous emissions. This appendix is designed to provide sufficient background information so that the reader can understand more fully the significance of pollution measurements, and the underlying principles. This information can be of value in dealing with air pollution officials, outside contractor personnel, and vendors of monitoring equipment.

D.1 Particulate Emissions

This section describes the procedure for obtaining a representative sample of particulate emissions. Information is presented relating to particulate measurements including particulate mass, particulate size and opacity.

D.1.1 Sampling Particulate Emissions

Obtaining representative samples is one of the most important factors leading to valid emission measurements. In fact, it has been said that more errors result from poor or incorrect sampling than from any other part of the measurement process. To obtain valid emission samples requires the identification of proper sampling locations. Often the best locations can be hard to reach points which can be hazardous and high above ground.

The most critical sampling requirements are for the measurement of particulates. Very specific requirements for particulates have been established by EPA to assure that a representative sample is obtained. Bends in ducting lead to the stratification of particulate in duct regions downstream of the bend and a traverse will be required if a representative sample is to be obtained. The requirements for gaseous measurements are only slightly less rigorous, as gaseous stratification can also occur.

The selection of a sampling site and the number of sampling points needed are based on attempts to get representative samples. Rules for accomplishing this are established in the EPA New Source Performance Standards, NSPS (code of Federal Regulations, Title 40, Part 60, EPA, July 1, 1977 and as amended). The EPA NSPS have been established for compliance purposes. Because of their widespread use for compliance testing, the NSPS methods are often the standards of performance against which other methods are judged. They are also used for non-compliance purposes. The sampling site should be at least eight stack or duct diameters downstream and two diameters upstream from any bend, expansion, contraction, valve, fitting or visible flame. For rectangular ducts, the equivalent diameter can be calculated from the expression: Equivalent diameter = 2 (length x width)/length + width). After determining the sampling location(s), provision must be made to "traverse" the stack or duct. That is, the actual sampling must be performed at a number of traverse points in the stack. These multiple samples are necessary because of the extreme gradients of flow and concentration that occur in some ducts and to a lesser extent in stacks.

When the 8 downstream and 2 upstream diameter criteria cannot be met, EPA has specified a minimum number of sampling points for stack diameters greater than 0.6 m and less than 0.6 m. The minimum number of traverse points required is illustrated in Figure D-1. To use this figure, it is necessary to first determine the distances from the chosen sampling location to the nearest upstream and downstream disturbances. This distance is then divided by the diameter or equivalent diameter to determine the distance in terms of the number of duct diameters. Figure D-1 is then used to determine the minimum number of traverse points that corresponds (1) to the number of duct diameters upstream and (2) to the number of diameters downstream. If a different number of traverse points is required by disturbances upstream and downstream, the greater number is to be selected.

Samples are to be obtained from zones of equal areas. This is easy to visualize for a rectangular duct. Such a duct is shown in cross section in Figure D-2. Travese points would be located as the centroid of each equal area as is shown in Figure D-2.

Obtaining samples from zones of equal areas may be less clear for a circular stack because most people are not accustomed to determining areas of circular cross sections. Figure D-3 illustrates the circular cross section of a stack divided into 12 equal areas. Note that the division as shown requires that samples be obtained from stack ports which are at right angles. A chart for determining the location of traverse points on a circular stack is shown as Table D-1. The chart presents the percent of stack diameter from the inside wall to the traverse point. For example, if the stack is 30 meters wide and 10 traverse points are to be obtained along the stack diameter, the third point will be: 10 meters x 0.146 = 1.46 meters. That is, 1.46 meters from the stack wall.

Once the traverse points have been established, and safe access to the sampling location has been provided, velocity measurements are needed to determine gas flow.

Stack-gas velocity is determined from a measurement of the velocity pressure, made using a pitot tube. The velocity pressure is the difference between the total pressure (measured against the gas flow) and the static pressure (measured perpendicular to the gas flow).

The S-type pitot tube is specified by the EPA for measuring velocity. The S-type pitot tube is designed for easy entry into small holes in the stack wall, and because of its high relatively large openings does not readily plug when in the presence of high concentrations of particulate matter. However, it requires a separate calibration for the particular velocity being measured, and thus does not directly read the velocity pressure.

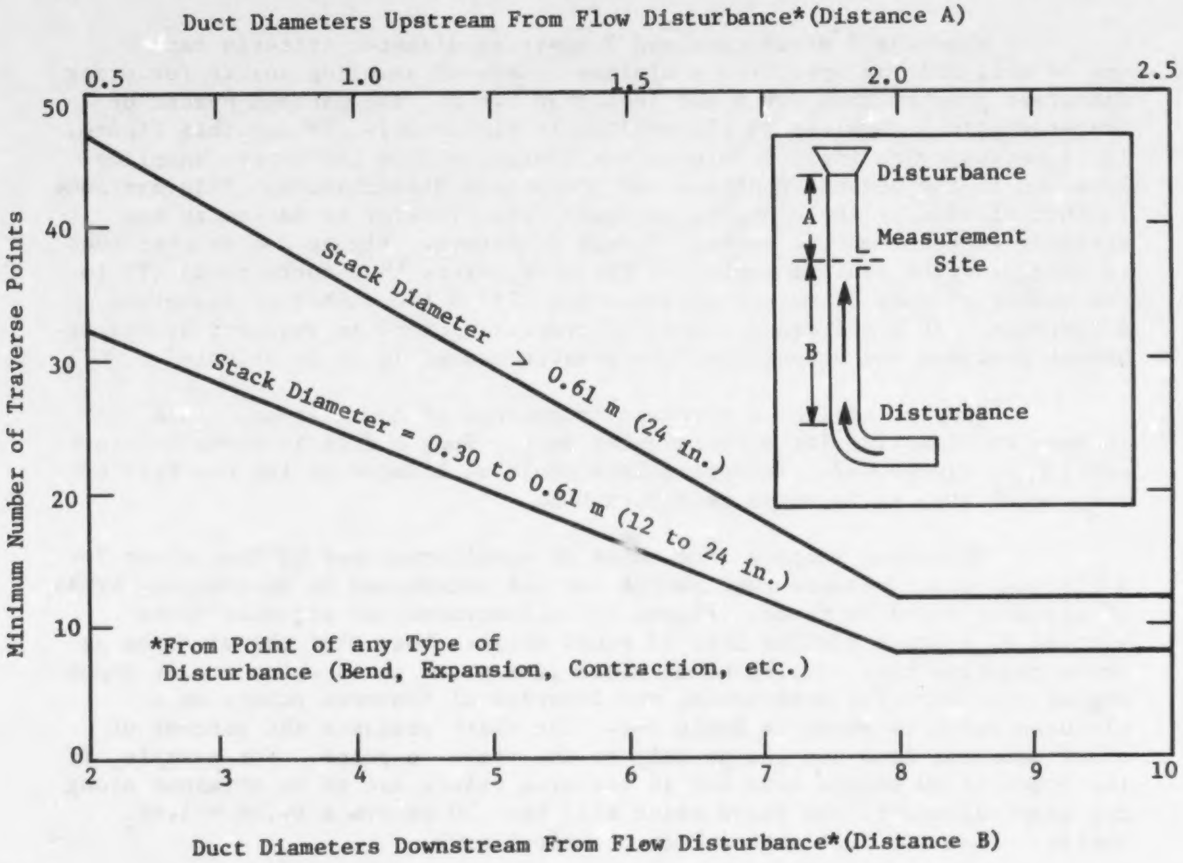
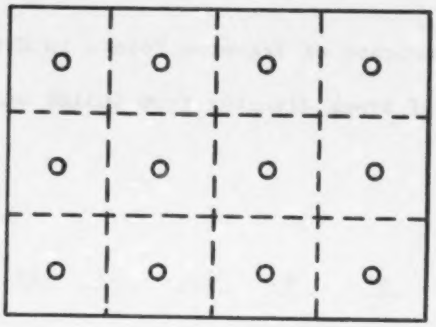


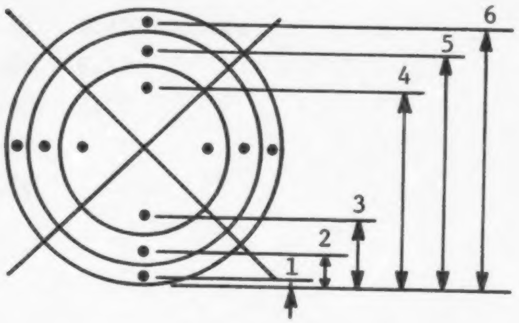
Figure D-1. Determination of the Minimum Number of Traverse Points.



Example showing rectangular stack cross section divided into 12 equal areas with traverse points at centroid of each area

Figure D-2. Duct Cross Section.

Traverse Point	Distance, % of Diameter
1	4.4
2	14.7
3	29.5
4	70.5
5	85.3
6	95.6



Example showing circular stack cross section divided into 12 equal areas, with location of traverse points, at centroid of each area.

Figure D-3. Circular Cross Section of Stack Divided into 12 Equal Parts.

TABLE D-1

Location of Traverse Points in Circular Stacks

(Percent of stack diameter from inside wall to traverse point)

Traverse point number on a diameter	2	4	6	8	10	12	14	16	18	20	22	24
1	14.6	6.7	4.4	3.3	2.5	2.1	1.8	1.6	1.4	1.3	1.1	1.1
2	85.4	25.0	14.7	10.5	8.2	6.7	5.7	4.9	4.4	3.9	3.5	3.2
3		75.0	29.5	19.4	14.6	11.8	9.9	8.5	7.5	6.7	6.0	5.5
4		93.3	70.5	32.3	22.6	17.7	14.6	12.5	10.9	9.7	8.7	7.9
5			85.3	67.7	34.2	25.0	20.1	16.9	14.6	12.9	11.6	10.5
6			95.6	80.6	65.8	35.5	26.9	22.0	18.8	16.5	14.6	13.2
7				89.5	77.4	64.5	36.6	28.3	23.6	20.4	18.0	16.1
8				96.7	85.4	75.0	63.4	37.5	29.6	25.0	21.8	19.4
9					91.8	82.3	73.1	62.5	38.2	30.6	26.1	23.0
10					97.5	88.2	79.9	71.7	61.8	38.8	31.5	27.2
11						93.3	85.4	78.0	70.4	61.2	39.3	32.3
12						97.9	90.1	83.1	76.4	69.4	60.7	39.8
13							94.3	87.5	81.2	75.0	68.5	60.2
14							98.2	91.5	85.4	79.6	73.9	67.7
15								95.1	89.1	83.5	78.2	72.8
16								98.4	92.5	87.1	82.0	77.0
17									95.6	90.3	85.4	80.6
18									98.6	92.3	88.4	83.9
19										96.1	91.3	86.8
20										98.7	94.0	89.5
21											96.5	92.1
22											98.9	94.5
23												96.8
24												98.9

Source: Code of Federal Regulations, Title 40, Part 60, EPA, July 1, 1977.

Isokinetic sampling is required if a representative sample of particulate is to be obtained. To be isokinetic, the velocity of the stack gas stream entering the probe nozzle must be the same as the velocity of the stream passing the nozzle. If the sampling velocity is too high (super-isokinetic sampling), there will be a disproportionately large concentration of small particles collected (because the inertia of the larger particles prevents them from following the stream lines into the nozzle). Alternatively, in sub-isokinetic sampling, where the sampling velocity is below that of the flowing gas stream, the gas samples would contain a higher-than-actual concentration of large particles (because heavier aerosol particles will enter the nozzle, but light particles will be diverted). Thus, even though isokinetic sampling is preferable, if the stack gas stream velocity fluctuates, it is better to sample slightly super-isokinetic than sub-isokinetic because of an increase of small particles has less effect on mass measurements than an increase of large particles. Isokinetic, super-isokinetic and sub-isokinetic sampling are schematically illustrated in Figure D-4.

It has been found that inertia effects become more significant when particle size exceeds about 3 micrometers in diameter. Therefore, if a reasonable proportion of the particles exceed this size, isokinetic sampling is necessary. Because of the requirement for isokinetic sampling, the sample volume extracted from each equal area zone will be proportional to the velocity, assuming the velocity to be constant.

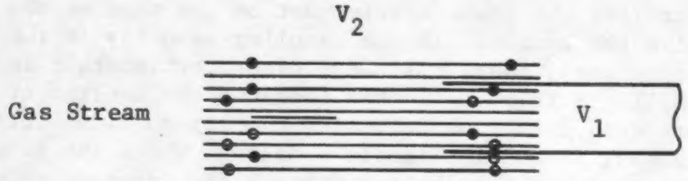
D.1.2 Particulate Measurements

This section discusses the types of particulate measurements which generally can be undertaken at power generation facilities. Certain particulate-related measurements at power plants are undertaken often and routinely, others less frequently and still others only on rare occasions, if at all.

One measurement which is made at many utility generating stations on a routine basis is opacity. Monitors for accomplishing this measurement are often permanently installed and operate continuously and on a real time basis.

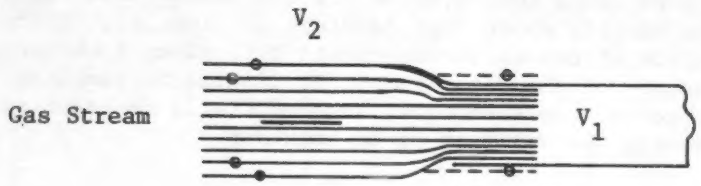
The measurement of particulate mass is generally made less frequently than that of opacity. The sample for particulate mass measurements is obtained on a grab sample basis. Sample collection can require up to several hours. Particulate mass measurements are frequently obtained for compliance or to evaluate precipitator efficiency. These measurements may be made by contractors who could require some form of governmental certification.

Measurements of particulate size are even less routine. There has, however, been increasing emphasis on the importance of very fine particle emissions (<2.5 micrometers) into the atmosphere. The inhalable particulate range, those less than 15 micrometers, is believed to have the greatest impact on health. The measurement of inhalable particle emissions and particle size distribution may some day be as commonplace as particulate mass measurements.


V_2
Gas Stream
V_1

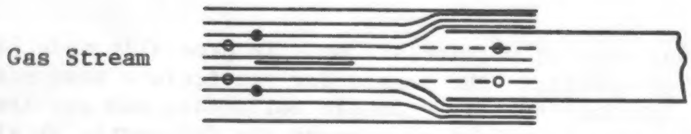
Isokinetic

$V_1 = V_2$


V_2
Gas Stream
V_1

Super-Isokinetic

$V_1 > V_2$



Sub-Isokinetic

$V_1 < V_2$

where V_1 = velocity in probe

V_2 = velocity in duct or stack

Figure D-4. Sampling Velocity and Potential Sampling Errors.

The following sections discuss:

1. Opacity
2. Particulate Mass
3. Particulate Size

D.1.3 Opacity

The measurement of opacity is perhaps the most widespread of all continuous source monitoring measurements made in the U.S. Opacity can be defined as the ratio of light attenuated by particulate emissions relative to the incident light. Monitors to accomplish this measurement are known as opacity meters or monitors, transmissometers or smoke meters.

The most commonly used opacity monitors are based on a system which measures the decrease in light transmission caused by particulates in a stack or duct. In a typical instrument the light source will be on one side of the duct and the photoelectric detector on the other. The measurement obtained is a function of the particulate concentration, and the wavelength of the radiation used, with appropriate compensation made for temperature. The width of the stack or duct is a permanent value which is used to calibrate the instrument.

It is necessary to measure the opacity of emissions in the visible range of the radiation spectrum if there is to be a meaningful correlation with the opacity value seen by an observer. Even if visible light is used, certain light attenuation instruments are often found to be biased toward large size particles and others toward small ones.

In order for an opacity monitor to remain in good operating condition, it is necessary to reduce to a minimum the effects of temperature and vibration. As a consequence, this type of instrumentation should be constructed ruggedly, with provision to maintain the specified optical alignment and clean optical surfaces. The latter is generally accomplished by blowing streams of air over the light source and detector. Typically, a split beam optical system is utilized. The source radiation is split into reference and measurement beams which are detected and compared. This referencing technique compensates for temperature effects in the stack and aging of the radiation source.

Opacity monitors are designed to automate the measurements of a trained observer. Such an observer will have been trained to identify the opacity of smoke plumes by observation at an EPA certified smoke school. Their training consists of observing controlled smoke plumes until they can identify the opacity settings at which the smoke generator was being operated.

Opacity read by the trained observer method is related to many factors, including meteorological conditions and position of the observer relative to the plume and the sun, as well as the makeup and concentration of particulates in the plume. Plume composition, particle size distribution and concentration, and stack diameter directly affect the optical characteristics of plumes and therefore what will be seen by observers. Meteorological conditions and plume dispersion play a particularly important role in plumes containing condensable emissions. It is therefore not surprising that a reading obtained by an in-stack opacity meter can differ from that obtained by an observer.

One advantage of using the opacity meter rather than the services of an observer is that a correctly aligned and properly functioning instrument produces a more consistent, more objective measurement which is easier to define in terms of physical concepts. Opacity monitors can also be used on a continual basis whereas observers can only function during the day under good atmospheric conditions.

D.1.4 Particulate Mass

- EPA Method 5

The EPA Method 5 train has been specified by the U.S. Environmental Protection Agency as the method to be used for particulate mass compliance testing of stationary sources. It is a grab sample technique in which particulate matter is withdrawn isokinetically from a stack or duct and trapped in an out of stack particulate filter. The method 5 stack sampler is shown in schematic in Figure D-5 and a typical version is illustrated in Figure D-6. Versions of the EPA Method 5 sampling train are commercially available from a number of manufacturers, the most common systems being operated at 1 cfm. A large volume system (5 cfm) is available for sources having lower particulate concentrations. The train and the procedure for its use are described in detail in Code of Federal Regulations, Title 40, Part 60, EPA, July 1, 1977 and as amended. The train will be discussed here briefly.

The stack gas is extracted isokinetically through a nozzle and is pulled through a heated probe and heated collection box. The box contains a cyclone to separate out large particles (>7 mm) and a filter with a collection efficiency greater than 99.5+%. The gas is then cooled and dried in a series of chilled impingers. Isokinetic flow is achieved using a vacuum pump and valve. The appropriate flow is determined from the flow measurement using a pitot tube by the use of a nomograph or calculator. The dry gas meter registers the gas flow.

In obtaining the particulate mass measurement, the filtering medium is weighed before and after sampling. To that weight difference is added the cyclone catch and particulate removed by washing from the probe and sampling train, after drying. This represents the total mass. By knowing the volume sampled, emissions expressed as mass per volume of stack gas can be calculated.

As noted above, EPA Method 5 is the method to be used for all compliance testing. Because of its widespread use, it is the method with the greatest amount of resource data available and with the greatest number of experienced practitioners of the art.

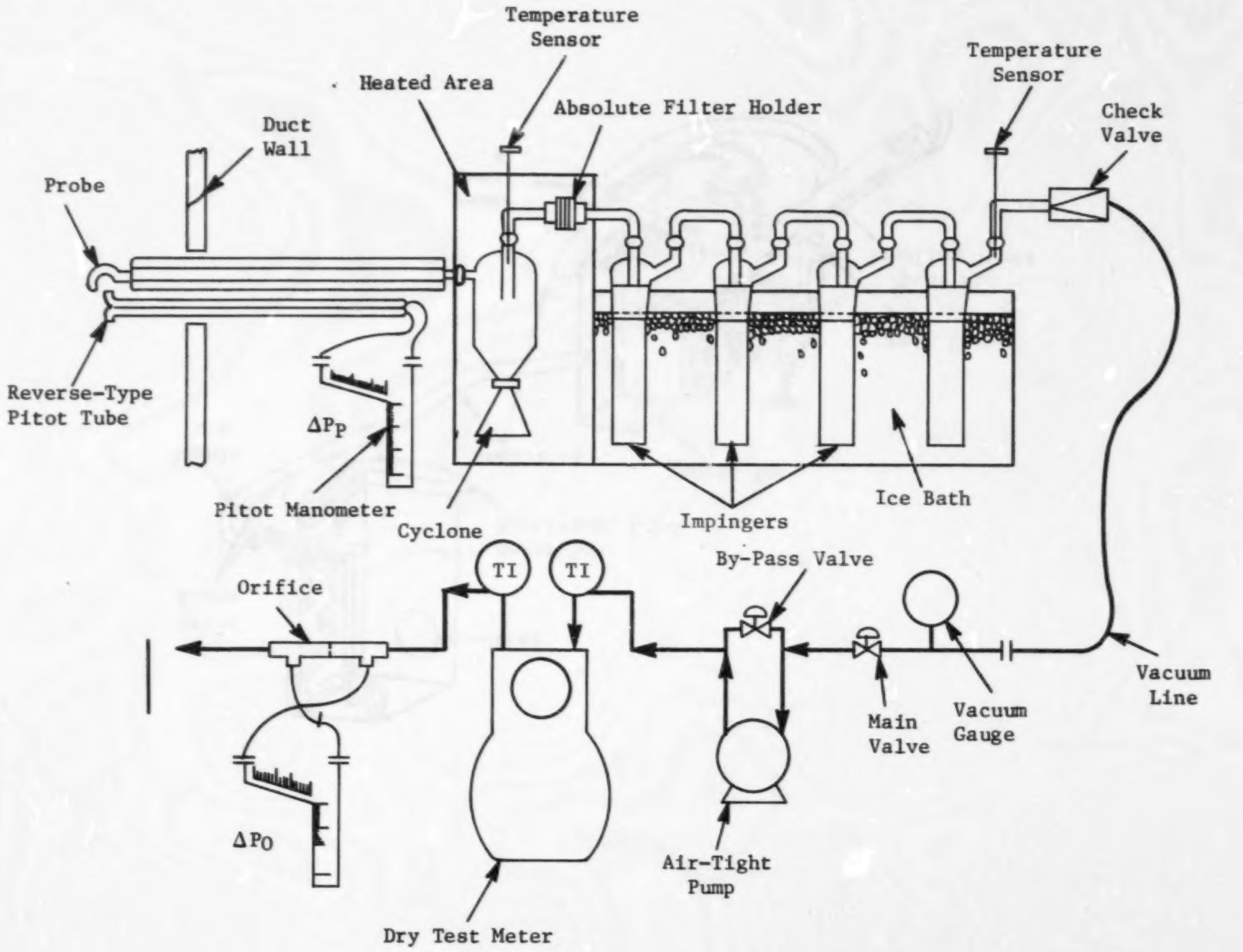

Temperature Sensor
Heated Area
Absolute Filter Holder
Temperature Sensor
Check Valve
Duct Wall
Probe
Reverse-Type Pitot Tube
ΔPp
Pitot Manometer
Cyclone
Impingers
Ice Bath
TI
TI
By-Pass Valve
Orifice
Vacuum Line
Main Valve
Vacuum Gauge
ΔPo
Air-Tight Pump
Dry Test Meter

Figure D-5. EPA Method 5 Sampling Train Schematic.

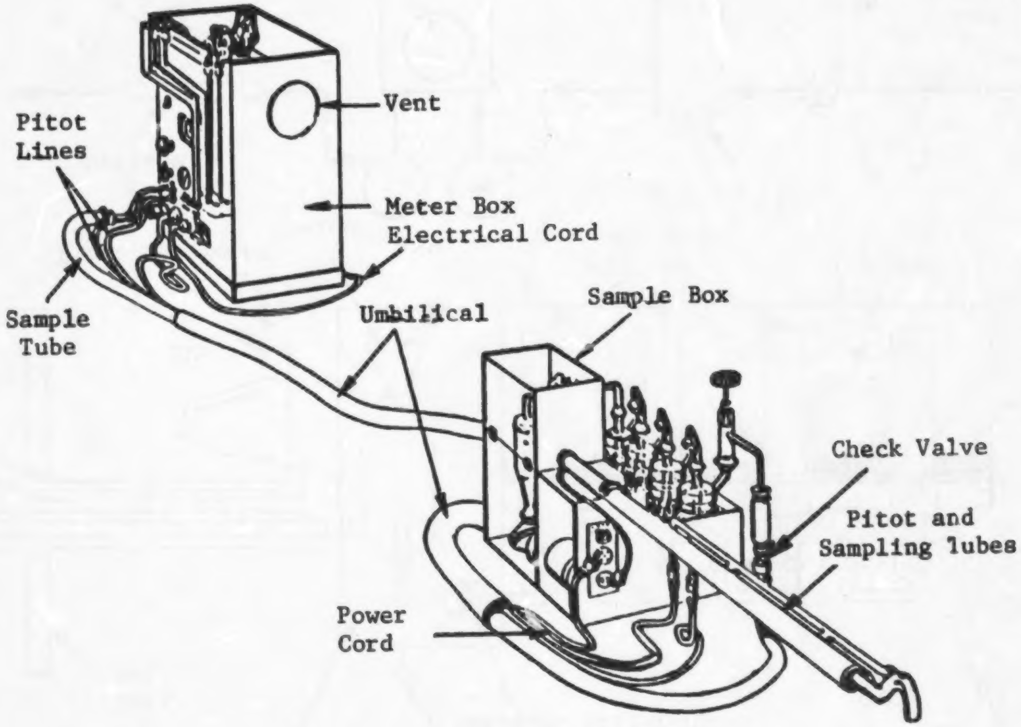

Pitot Lines
Vent
Meter Box
Electrical Cord
Sample Tube
Umbilical
Sample Box
Check Valve
Pitot and Sampling Tubes
Power Cord

Figure D-6. EPA Method 5 Sampling Train Illustration.

- **Automtated Particle Mass**

Over the years attempts have been made to obtain particle mass measurements on a continuous basis. Although some have been sold commercially, most are experimental in nature. In certain cases, the readings of opacity meters can be correlated on a case by case basis with mass emissions using a reference technique such as Method 5 as a calibration tool. One automated measurement method which has been commercially available uses beta radiation attenuation. This system uses extractive sampling. It has been found that probe losses are so significant that the data cannot be considered valid. Until an improved transport system or an in situ particulate mass monitor is developed, manual methods will continue to be used.

D.1.5 Particulate Size

The measurement of particulate size is not undertaken routinely at power plants. It is, however, performed with sufficient frequency and for a sufficient number of purposes (such as to evaluate the efficiency of particulate removal equipment) to warrant its inclusion here. The most widely used device utilized to obtain particulate size distribution measurements is the cascade impactor. This device can be used in the stack or externally in association with an extractive sampling system. In-stack use of a cascade impactor is preferable as it eliminates sample losses in the probe which could influence the particulate size distribution obtained. Use of the in-stack system is generally more difficult than using an external system. Used externally, the cascade impactor is placed in the heated sample box associated with Method 5 equipment. Typically a tap is taken off at the primary Method 5 stream.

The cascade impactor permits simultaneous collection and sizing of the particulate emissions. Cascade impactors such as the Andersen and the Brink collectors are multi-stage devices depending upon particle momentum and aerodynamic drag to achieve separation. At each stage, successively smaller particles are separated from the gas stream and are deposited on collection plates. A final filter removes those particles passing through the impaction stages, with the extent of recovery being limited by the collection efficiency of this filter. The particle size distribution is obtained by measuring the mass of particulate collected by each stage. Total particulate mass is the sum of the collected mass of each stage plus the mass collected by the final filter.

Problems associated with the use of cascade impactors include:

- wall losses (some particles may adhere to impactor walls rather than to collector stages).
- reentrainment (not all the particles striking a collector stage stick to it).
- weighing accuracy (the mass of the particles accumulated on certain stages may be so small as to be almost unmeasurable unless an extremely sensitive balance is used).

- isokinetic sampling (the design of a cascade impactor requires that the flow cannot vary during the run. If the stack gas flow varies, the sample rate may not be variable unless only a slip stream is being used to supply stack gas to the impactor).

Cascade impactors are generally used to divide particulates into a number of fractions. Thus, 8, 10 or more stages are common with impactors. When fewer cuts are desired, appropriately sized cyclones plus a final filter in a Method 5-type heated sample box can be used to get a size distribution. Another system using either 3 or 5 cyclones in situ has also been tested.

Advanced instrument systems for obtaining particle size distribution have been under development for a number of years. None, however, are in widespread use.

D.2 Gaseous Emissions

This section describes considerations important in the sampling of gaseous emissions. Also included is information on frequently used reference methods of gas analysis as well as on instrumental methods of gas analysis.

D.2.1 Gaseous Emissions Sampling

Sampling for gaseous emissions involves the same type of procedures as in particulate sampling. Again, it is very important to obtain a representative sample. Typically, in a power plant, most routine gaseous measurements will be obtained using permanently installed continuous monitoring instruments. These may be solid state systems or wet chemical. Alternatively, grab samples may be obtained. These are usually analyzed using wet chemical methodology. Within the last few years, in situ, i.e., in-stack, monitors have been developed which do not require sampling systems. In situ monitors are based on optical principles and sight completely across a duct or stack thereby eliminating the need for multipoint meaurements. In situ monitors of this type are available for some of the most common gaseous pollutants and also opacity measurements. To differentiate between in situ and the techniques in which a sample is withdrawn, the latter are termed extractive. In addition to locating an appropriate sampling point, extractive sample consists of the following operational elements.

- Sample extraction
- Sample transport
- Sample conditioning
- Sample analysis

As in particulate sampling, extractive sampling for gases requires introducing a sampling probe into a stack source and withdrawing a sample. Analysis may be performed using wet chemical methods or continuous monitoring instrumentation. In the case of wet chemical analysis, the sample is drawn through a sampling train into a collection medium. The collection medium may be in the form of filters or a set of bubblers which are then taken to the laboratory for analysis. Continuous monitoring is much more efficient, productive, and less time consuming than laborious grab sampling and wet chemical analytical method, but requires a greater capital investment. Regardless of the analytical method employed, the fact remains that after a sample has been extracted from the source it requires sample transport and sample treatment to ensure that the sample presented for analysis is compatible with the analytical procedure that follows. Also, the method chosen may depend on the nature of the tests. If measurements are taken for compliance, it will be necessary to use required reference techniques.

Several potential sources of error can exist in the sampling system prior to the instrument. Sample integrity can be destroyed by:

- Chemical reaction with surface materials
- Chemisorption on particulate matter
- Water condensation in the sampling line
- Leaks in the sampling line

Extractive source monitoring systems either condition the sample and follow with an analyzer for measurement at source level concentrations or condition the sample by a dilution network coupled with an ambient air level instrument. Conventional source level sampling systems employ a probe filter for particulate removal and a drying device (usually a refrigerated dryer) before the measurement is made. Permeation drying tubes, which operate on the permeation distillation principle, have also become popular for moisture removal.

Recently a new concept has been introduced in source level extractive monitoring which is termed reflux filtration. In this system the sample from the stack is drawn through the clean reflux sample stream where dirt particles and aerosols (acid mist) are blown back by the action of high velocity gas molecules. After the sample is scrubbed, it passes through a guard filter and then is pressurized by a pump. A small portion of the sample is sent to the dryer but most of the sample is sent back as the clean reflux sample stream. After scrubbing the incoming sample, the reflux stream, along with dirt particles, discharges into the process stream.

Dilution techniques can offer an advantage in sample conditioning by eliminating heated sample lines and water vapor removal system, if the stack gas sample can be quantitatively diluted as close to the source as possible. Dilution systems also offer the advantage that both ambient air and source monitoring could be accomplished by the same instrument.

If stratification of gaseous pollutant species exists, more than one sampling inlet may be required to approach the equal areas concept noted for particulates. Indeed, it has been found experimentally that stratification does exist in the flue gas ducting of power plants and the single point sampling is inappropriate for obtaining representative gas samples. A typical SO_2 concentration stratification contour measured for a utility boiler is shown in Figure D-7. To reduce the significance of gaseous stratification multipoint sampling can be used to sample from the inner 50% of the duct. Results of in-stack tests, as opposed to in-duct tests,

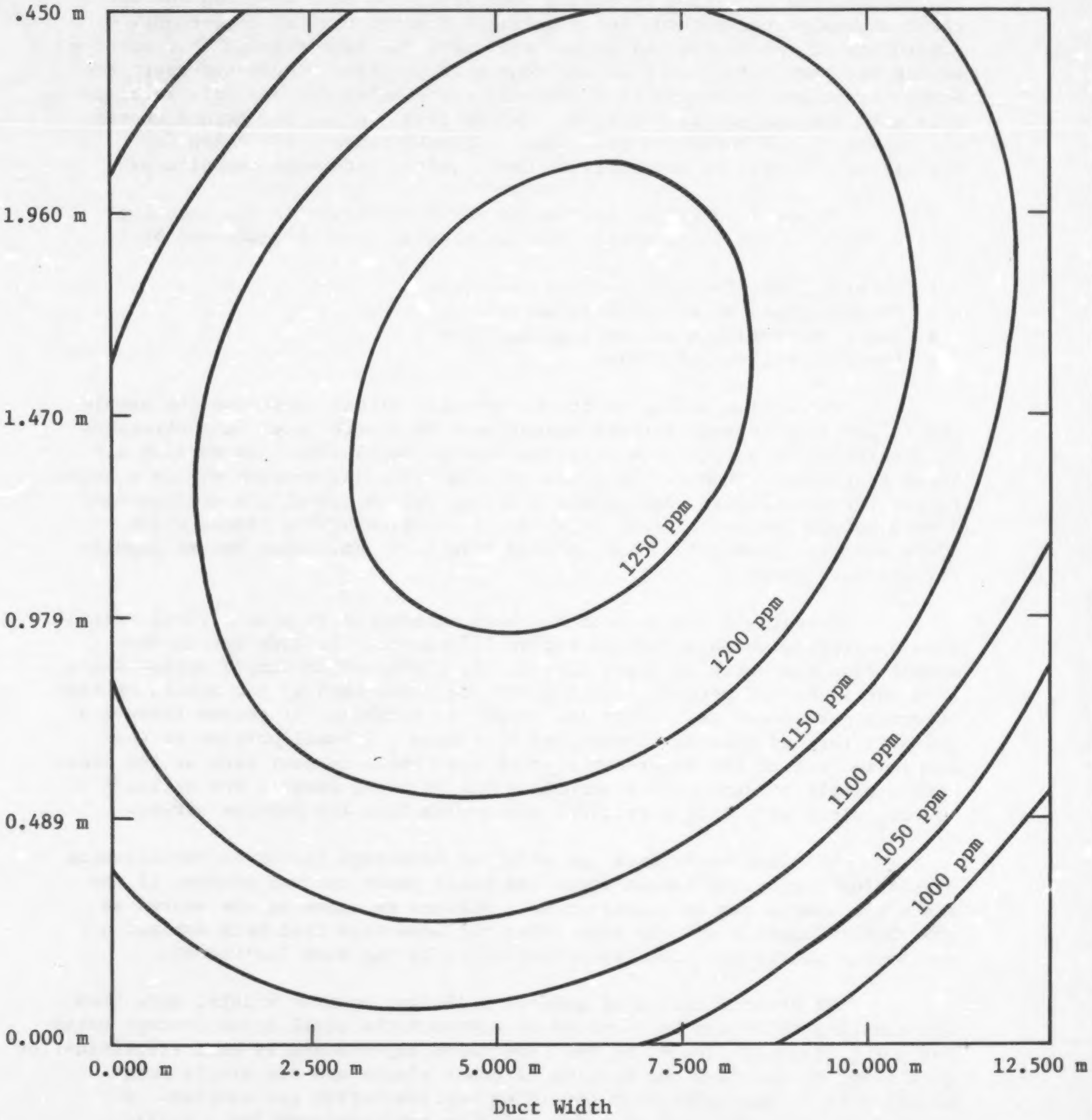


Figure D-7. SO_2 Profile.

indicated that stack conditions are extremely uniform and should be the preferred extractive sampling location, provided that practical access to such a sampling location is available. One drawback to stack sampling is that air leakage into the air preheater can result in dilution of stack emissions. Sampling between the economizer and air preheater will eliminate this problem.

Frequently Used Reference Methods for Gas Analysis

The EPA new source performance standards specify methods to be used in measuring certain pollutants. Some of these methods are wet chemical and others are not. Wet chemical methods are generally not used for continuous or routine monitoring, because instrumental methods generally can accomplish the measurement far more efficiently. However, in certain cases no satisfactory instrumental method has been developed and wet chemical methods continue to find utility. This section describes briefly the reference methods for SO_3/SO_2, NO_x, and CO. The first two are wet chemical and the last is instrumental. The SO_3 measurement is one for which no instrumental method is available and so it is used perhaps more frequently than any other wet chemical source monitoring technique. The descriptions which follow are not meant to be complete but they provide a feel for general requirements. Additional details on the methods described can be found in the Code of Federal Regulations, Title 40, Part 60, EPA, July 1, 1977 (and as amended).

- SO_2/SO_3 Reference Technique (EPA Method 8)

In this method, a gas sample is extracted at temperatures above the acid mist dew point. As a consequence, SO_3 will be present as a vapor, not a particulate. The flue gas is extracted from the exhaust stream through a heated probe. The sample is then passed through two absorbing solutions in a total of three impinger bottles. The first contains an 80% isopropyl alcohol solution to absorb the sulfur trioxide. Two subsequent impingers contain a hydrogen peroxide solution to absorb the SO_2. A filter located between the isopropanol impinger and the first peroxide impinger traps any SO_3 mist which is not absorbed by the isopropanol. The quantities absorbed are determined by chemical titration using barium perchlorate as the titrant and thorin as the indicator. The concentrations of the individual sulfur oxides can then be used to calculate the SO_3/SO_2 ratio.

A high level of care must be exercised if the determination is to be performed properly. After sampling, the train must be purged with air for at least 30 minutes in order to release the SO_2 which might have been retained by the isopropanol.

- NO_x Reference Technique (EPA Method 7)

The gas sample is collected in an evacuated flask containing dilute sulfuric acid-hydrogen peroxide absorbing solution. The nitrogen oxides, except for nitrous oxide, are oxidized to nitric acid by the hydrogen peroxide. After careful destruction of the peroxide with heat, the nitric acid produced is measured of the peroxide with heat, the nitric acid produced is measured colorimetrically as nitrophenol-disulfonic acid. The laboratory procedure is lengthy, requires a number of steps, and analysis must be performed by a qualified laboratory technician. Errors may arise due to improper procedures and deterioration of reagents. This method is suitable for NO_x concentrations between 15 and 1500 ppm by volume and has a sensitivity of about 1.5 ppm.

- CO Reference Technique (EPA Method 10)

An integrated or grab sample is extracted and analyzed for CO content using a nondispersive infrared analyzer. Any substance having a strong absorption of infrared energy will interfere to some extent. Discrimination ratios for H_2O and CO_2 are 3.5% H_2O per 7 ppm CO and 10% CO_2 per 10 ppm CO, respectively, for devices measuring in the 1500 to 3000 ppm range. For devices measuring in the 0 to 100 ppm range, interference ratios can be as high as 3.5% H_2O per 25 ppm CO and 10% CO_2 per 50 ppm CO.

D.2.3 Instrumental Methods of Gas Analysis

A large number of instrumental methods have been utilized to monitor gaseous pollutants. The earliest instruments available were simply automated versions of wet chemical procedures. Colorimetric and electrochemical techniques predominated. Over the years, however, there has been a pronounced movement towards all solid state instrumentation, which frequently is based on optical techniques. Table D-2 provides an indication of the large number of methods which have been used in pollution monitoring.

The outline of instruments used for monitoring gaseous pollutants on a source basis presented here is divided into two sections: instruments which require an extracted sample, and those which measure across a stack or duct without extracting a sample, the in situ instruments.

D.2.3.1 Extractive Instrumentation

Most continuous source emission measurement methods utilize extractive sampling in which a gas sample is withdrawn from a stack or duct. With most instrument methods, the sample is sent through sample lines to a sample conditioning system and from there to the measurement instrument. The sample conditioning system prepares the gas for analysis, making it possible for the analyzer to perform effectively and minimize interferences. The sample conditioning required varies from method to method. It generally involves filtration to remove particulates and frequently includes a water removal system such as refrigeration coils and/or permeation driers. Certain instruments may require only heated sampling lines to prevent the condensation of water. To withstand the corrosive effects of flue gases, the complete sampling system must be constructed of 316 stainless steel, Teflon or other materials not easily affected by stack gases. Extractive instrumentation is potentially cheaper than other systems such as in situ in that more than one analyzer can monitor more than one emission source on a sequential basis. Extractive instrumentation may also be more accessible for servicing than an in situ monitor which could be located high on a stack.

TABLE D-2

TECHNIQUES FOR ANALYZING GASES AND VAPORS IN FLUE GASES

	NO_x	SO_2	CO	HC
Wet Chemical			X	
Colorimetric	X	X		
Color titration		X		
Electrochemical				
Coulometric transducer	X	X		
Radiation Attenuation				
Nondispersive infrared absorption	X	X	X	X
Ultraviolet absorption	X	X		X
Photometric				
Chemiluminescence	X			
Flame photometer		X		
Pulsed fluorescense		X		
Flame Ionization				X
Gas Chromatography		X	X	X

The following paragraphs describe the most widely used extractive instrumentation for monitoring the criteria pollutants of NO_x, SO_2, CO, and hydrocarbons. A brief description of the operating principles of these instruments for each type of pollutant noted is given here for the benefit of the reader. The methods used include:

- NOx
  - Chemiluminescent
  - UV absorption
  - Electrochemical
  - NDIR

- SO2
  - UV absorption
  - NDIR
  - Pulsed UV fluorescence

- CO
  - NDIR

- HC
  - FID
  - NDIR

D.2.3.1.1 NOx

- Chemiluminescent

Instruments designed using the chemiluminescent principle utilize the light given off from the reaction between NO and ozone, O_3. A photomultiplier tube detects the light emitted by this reaction. Because of the nature of the reaction and filters that screen out illumination resulting from other possible reactions, the chemiluminescent technique is largely interference free. The method is also highly sensitive with models being available to measure ambient as well as source NO_x. The technique does, however, require extensive sample preparation including removal of particulates and much water vapor. Also many instruments operate at negative pressures to permit the reaction to go more smoothly. Although this can add to mechanical complexity, most of the commercially available chemiluminescent instrumentation is reported to work quite well.

As noted above, the reaction is between ozone and NO. To monitor total NO_x, i.e., to get a value for NO_2, the NO_2 must first be reduced to NO. This is typically accomplished using converters constructed of stainless steel, molybdenum, carbon or catalysts such as gold and tantalum. Thus, values can be obtained for NO, NO_2, or total NO_x.

- UV Absorption

This instrumental method uses the absorption of ultraviolet radiation by NO_2 molecules over a heated, several foot long path length optical cell. NO has little absorbence in the visible and UV range and consequently it must be converted to NO_2 to be monitored. This is accomplished by reacting NO with oxygen at a pressure of 5 atmospheres. The use of high pressure oxygen may be undesirable in certain applications and environments but few problems have been reported. UV absorption instruments utilize a heated sample line and an "all hot" system to prevent condensation of water and SO_x. This analyzer requires no further conditioning because particulates, water vapor and other stack gas constituents do not interfer because of a split beam arrangement. Some UV absorption instruments for NO_x also have the capability for monitoring SO_2 as well by a change in wavelength. This is generally done on a sequential basis with one pollutant monitored for a given period, then another.

- Electrochemical

An electrochemical transducer has found widespread use as a NO_x analyzer. Typically a gas sample is passed through a membrane and into an electrochemical cell. A signal is generated within the cell which is proportional to the NO_x concentration in the gas sample. This signal is amplified and displayed on a meter. Some versions of electrochemical NO_x analyzers can also be used to determine SO_2, and generally these instruments are equipped with plug-in interchangeable detectors, one for each gas. These detectors can be changed as the measurement need requires.

Electrochemical instruments are inexpensive, rugged and simple to use. They can give reasonably reliable readings when properly calibrated. There are, however, a number of potential interferences and the electrochemical cells require frequent replacement.

- NDIR

Non-dispersive techniques (IR or UV) have been used for monitoring many gases throughout the years. Typically, energy from a source is split into two beams, one of which passes through a cell containing the gas to be monitored, and the other passes through zero reference cell without this gas. The intensity of the radiation passing through these two cells is compared yielding a concentration measurement. Non-dispersive instrumentation has been used extensively in the past to measure NO, although newer instrumental methods are more selective, interference-free and require less maintenance. The maintenance of NDIR systems is genearlly considered to be high relative to other techniques and the use of NDIR instrumentaiton to measure NO has diminished. In addition, water and CO_2 are known to interfere. Thus, NDIR requires extensive sample conditioning such as the removal of water vapor and particulate.

D.2.3.1.2 SO2

- UV Absorption

The UV absorption method for SO_2 is very similar to that used for NO_x. As noted under NO_x monitors, some SO_2/NO_2 monitors are convertible. The instrument can alternately monitor SO_2/NO_2 by automatically changing the optical filter to select the appropriate light wavelength for each measurement. The UV absorption instrument for SO_2 has the following characteristics:

- all hot sampling and measurement system
- long path length
- minimal interference

- NDIR

Non-dispersive infrared spectroscopy was one of the original methods used to monitor for SO_2. Non-dispersive techniques (IR or UV) have been used for monitoring many gases throughout the years. Typically, energy from a source is split into two beams, one which passes through a cell containing the gas to be monitored, and the other passes through a zero reference cell without this gas. The intensity of the radiation passing through these two cells is compared yielding a concentration measurement of SO_2. Non-dispersive instrumentation can no longer be recommended for most applications because new instrumental methods are more selective, interference-free and require less troublesome maintenance. The maintenance of NDIR systems is generally considered to be high relative to other techniques. In addition, water and CO_2 are known to interfere. Thus, NDIR requires extensive sample conditioning such as the removal of water vapor and particulate. Water removal via a condensation system is especially tricky because of the solubility of SO_2 in water. NDIR is no longer recommended for SO_2 measurements but it has been used extensively.

- Pulsed UV Fluorescence

The commercial availability of pulsed fluorescence instrumentation for source monitoring is relatively recent. It is, however, a highly regarded method for the measurement of SO_2. A sample is drawn into a chamber where it is irradiated with a brief pulse of ultraviolet light. This causes SO_2 molecules to emit characteristic radiation which is directly proportional to their concentration. The judicious choice of wavelength for excitation and emission radiation filtering is designed to minimize interference from other potential interferents such as water vapor, oxygen and nitrogen. The pulsed fluorescence technique does require some sample conditioning, specifically the removal of particulate matter and sufficient water vapor to prevent condensation.

D.2.3.1.3 CO

- NDIR

Non-dispersive infrared is a widely used method for monitoring CO emissions. It is, in fact, specified in the EPA NSPS as Method 10. The NDIR system for CO works exactly in the same way as for SO_2. Here, too, interference can be a big problem. Any substance having a strong absorption of infrared energy will interfere to some extent. Discrimination ratios for H_2O and CO_2 are 3.5% H_2O per 7 ppm CO and 10% CO_2 per 10 ppm CO, respectively, for devices measuring in the 1500 to 3000 ppm range. For measuring in the 0 to 100 ppm range, interference ratios can be as high as 3.5% H_2O per 25 ppm CO and 10% CO_2 per 50 ppm CO. Interference from water vapor can be minimized by reducing the humidity, by using refrigeration (water solubility is a problem here, too, but it is less than with SO_2), drying agents, or by the use of filters.

D.2.3.1.4 Hydrocarbons

- Flame Ionization Detector

The flame ionization detector, FID, is the most widely used analytical method for total hydrocarbons. It is continuous and real time. Typically with this system an emission gas sample is introduced into a hydrogen flame. The combustion of hydrocarbons, HC, produces ionization which is proportional to the number of carbon atoms present. A current collector in the vicinity of the flame collects the ions generated and the current which results is proportional to the number of carbon atoms in the gas stream. The presence of nitrogen, halogen or oxygen atoms attached to HC molecules lowers response somewhat. Other carbon-containing species such as CO and CO_2 do not interfere, and water vapor interference is minimal. A number of different types of HC can be present but the standard FID cannot distinguish among them. Differentiation among HC is possible using a gas chromatograph, GC, to initially separate HC before they are introduced into the FID for monitoring. Use of a GC will reduce the FID instrument's real time capabilities but should permit a true reading of individual hydrocarbons.

- NDIR

NDIR was one of the earliest techniques used for hydrocarbon monitoring. In monitoring HC, this technique is subject to the interferences of water vapor and CO_2 noted earlier for other NDIR applications. Thus, an extensive sample conditioning system is required. NDIR also responds differently to different categories of hydrocarbons, being sensitive to paraffins and only about 5% as sensitive to aromatics.

D.2.3.2 In situ Instrumentation

In situ monitoring of pollutants is a relatively recent development. A typical stack or duct-mounted system consists of a light source, detector-analyzer and a mounting pipe. In situ monitor is in fact an absorption spectrometer in which the cell path length is the width of the stack or duct. The light source sends a polychromatic radiation beam through the gas to be measured. The detector-analyzer receives the beam and separates it into the wavelength(s) to be measured. The beam intensity at the measurement wavelength is ratioed with a nearby nonabsorbing wavelength and the resulting electronic signals are translated into pollutant mass. Knowing the gas stream temperature and pressure, the total volume can be determined and thus the emission concentration calculated.

The reading given by an in situ system is rapid in that the sample is measured right in the stack or duct and need not be moved to an analyzer. It is potentially unaffected by stratification in that it obtains an "optical traverse" across the gas stream being measured. It is also unaffected by the presence of particulates because of the ratioing procedure and of course requires no sample conditioning. For a single installation it is potentially cheaper than an extractive system in that it requires no sample conditioning system and the ability to measure more than one species can be added in a modular manner.

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Disadvantages most often noted are keeping the system optically aligned, properly calibrated, and temperature compensated. A manufacturer of this type of instrumentation has undertaken extensive studies to compare the results obtained with the wet chemical PDS reference method. In all tests shown, agreement between the methods was very good.*

In situ instrumentation is commercially available or has been developed for a number of pollutants including NO, SO_2, CO, CO_2, HC, H_2S, NO_2 and NH_3.

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*"Analytical Methods Applied to Air Pollution Measurements" by R. K. Stevens and W. F. Herget, published by Ann Arbor Science Publishers, Inc., Chapter 11, by H. C. Lord "Adsorption Spectorscopy Applied to Stationary Source Emissions Monitoring."

APPENDIX E

BOILER EFFICIENCY

Experience has shown that carbon content on particulate tends to increase under low NO_x operating conditions, especially in front wall fired and on some horizontally opposed fired boilers. While this does not necessarily happen in all cases, it is obvious that when carbon loss does increase the effect is to lower boiler efficiency. However, if the CO limit of 200 ppm maximum in the flue gases is strictly observed as a criteria for setting up the optimum NO_x emission firing mode, then efficiency should not be impaired or changed since any loss in efficiency due to increased carbon loss will be offset by the increase in efficiency resulting from operating at low excess air. Unfortunately, unless at least a brief form of efficiency test is conducted it will not be known whether boiler performance under low NO_x conditions is equal to or less than efficiency at baseline operation.

ASME EFFICIENCY TEST

Once the test program has been completed and the optimum low NO_x emission operation modes have been defined, it is recommended that baseline and optimum low NO_x tests be repeated but, this time, additional data should be obtained to be able to calculate boiler efficiency. With the required data in hand, boiler efficiency may be readily calculated using the A.S.M.E. Steam Generating Units, Power Test Codes, Abbreviated Efficiency Test, heat loss method. Examples of typical performance data required and calculations made are shown in ASME test forms shown in Tables E-1 and E-2. Two pieces of information are required to make these calculations in addition to some of the test data taken during the test program. These are: (1) ultimate fuel analysis on an as received basis, and (2) percent carbon on particulate. The ultimate analysis is not generally available in most power plants and requires taking coal samples during the test and submitting them to the laboratory for the required determinations. Likewise, carbon loss data also are not readily available and must be obtained by extracting particulate samples simultaneously as each test is run and analyzing for carbon content. Particulate samples may be obtained using a variety of test techniques. The prescribed method for obtaining representative samples under isokinetic conditions for compliance with particulate emission regulations is EPA Method 5 as printed in the Federal Register, Vol. 36, No. 247, December 23, 1971 (and as amended). This method, however, requires considerable effort to conduct the test and, since the objective is not compliance, other more simple methods could be used, such as, the alundum thimble apparatus which is more simple and easier to operate. This apparatus is an "in stack" sampler with the thimble located in the flue gas stream requiring no external heating complications. Fly ash samples are collected in the thimble as the sample gases are drawn through the apparatus isokinetically. The plant engineering department or results department personnel should be consulted for assistance in obtaining suitable particulate grab samples for this purpose.

For ready reference, the following are the required data necessary for the A.S.M.E. Abbreviated Efficiency Test:

- Coal as fired ultimate analysis

  (1) Moisture
  (2) BTU
  (3) Carbon
  (4) Hydrogen
  (5) Sulfur
  (6) Ash

- Percent carbon on particulate (fly ash)
- Temperature of air for combustion
- Gas temperature leaving boiler, economizer, air heater
- Flue gas analysis (percent by volume)

  O_2
  CO_2
  CO

  N_2 (by difference)

Efficiency calculations may be made using the above data for each test. The efficiency for "Low NO_x" emission operation can then be compared to baseline operation efficiency to make sure that there is no loss in efficiency for low NO_x operation. As indicated above, if the 200 maximum ppm CO limitation is observed as the criteria for setting up the low NO_x combustion mode, efficiency should be equal to or greater than that at baseline conditions. If not, excess air should be increased for the firing mode in question and efficiency tests repeated until optimum conditions are established.

PERFORMANCE CHECKS FOR EFFICIENCY

Once optimum conditions for the low NO_x emission combustion modes have been determined, test data should be recorded and filed for future reference and comparison with similar data obtained in periodic checks of boiler performance (efficiency). These spot checks, however, need not be calculated by the A.S.M.E. method requiring ultimate analyses and carbon loss data as discussed above but, instead, can be made simply by a spot check of combustion conditions. The important combustion criteria affecting boiler performance are O_2 or CO_2, CO, exit gas temperature and stack opacity. Operation of the boiler should be set up duplicating optimum low NO_x conditions with controls either on automatic but preferably on hand control and the boiler locked out of the automatic dispatch control load control system. This way the boiler will operate at constant load and the above measurements and observations can then be made at steady state conditions and the results compared to previous data recorded for the more complete efficiency tests. Deviations in the values of O_2 or CO_2, CO, exit gas temperature and stack opacity will pinpoint changes in efficiency. The reliability of the spot check will, of course, be dependent on the accuracy of the values measured, especially with reference to O_2 and CO. Assuming no major or drastic

TABLE E-1

ASME TEST FORM
FOR ABBREVIATED EFFICIENCY TEST

SUMMARY SHEET PTC 4.1-a(1964)

TEST NO. 1A BOILER NO. 6 DATE 4-18-72

OWNER OF PLANT TVA LOCATION Widows Creek

TEST CONDUCTED BY Esso Research & Engineering Co. OBJECTIVE OF TEST Boiler Performance DURATION 4 Hrs.

BOILER, MAKE & TYPE B&W Radiant RATED CAPACITY 125 MW

STOKER, TYPE & SIZE

PULVERIZER, TYPE & SIZE Type E BURNER, TYPE & SIZE

FUEL USED Bituminous Coal MINE COUNTY STATE SIZE AS FIRED

PRESSURES & TEMPERATURES

1	STEAM PRESSURE IN BOILER DRUM	psia	
2	STEAM PRESSURE AT S. H. OUTLET	psia	
3	STEAM PRESSURE AT R. H. INLET	psia	
4	STEAM PRESSURE AT R. H. OUTLET	psia	
5	STEAM TEMPERATURE AT S. H. OUTLET	F	
6	STEAM TEMPERATURE AT R.H. INLET	F	
7	STEAM TEMPERATURE AT R.H. OUTLET	F	
8	WATER TEMP. ENTERING (ECON.) (BOILER)	F	
• 9	STEAM QUALITY % MOISTURE OR P. P. M.		
10	AIR TEMP. AROUND BOILER (AMBIENT)	F	
11	TEMP. AIR FOR COMBUSTION (This is Reference Temperature) †	F	88
12	TEMPERATURE OF FUEL	F	
13	GAS TEMP. LEAVING (Boiler) (Econ.) (Air Htr.)	F	372
14	GAS TEMP. ENTERING AH (If conditions to be corrected to guarantee)	F	

UNIT QUANTITIES

15	ENTHALPY OF SAT. LIQUID (TOTAL HEAT)	Btu/lb	
16	ENTHALPY OF (SATURATED) (SUPERHEATED) STM.	Btu/lb	
17	ENTHALPY OF SAT. FEED TO (BOILER) (ECON.)	Btu/lb	
18	ENTHALPY OF REHEATED STEAM R.H. INLET	Btu/lb	
19	ENTHALPY OF REHEATED STEAM R. H. OUTLET	Btu/lb	
20	HEAT ABS/LB OF STEAM (ITEM 16 – ITEM 17)	Btu/lb	
21	HEAT ABS/LB R.H. STEAM (ITEM 19 – ITEM 18)	Btu/lb	
22	DRY REFUSE (ASH PIT + FLY ASH) PER LB AS FIRED FUEL	lb/lb	15.87
23	Btu PER LB IN REFUSE (WEIGHTED AVERAGE)	Btu/lb	912.1
24	CARBON BURNED PER LB AS FIRED FUEL	lb/lb	0.66
25	DRY GAS PER LB AS FIRED FUEL BURNED	lb/lb	11.6

HOURLY QUANTITIES

26	ACTUAL WATER EVAPORATED	lb/hr	
27	REHEAT STEAM FLOW	lb/hr	
28	RATE OF FUEL FIRING (AS FIRED wt)	lb/hr	
29	TOTAL HEAT INPUT $\frac{(\text{Item } 28 \times \text{Item } 41)}{1000}$	kB/hr	
30	HEAT OUTPUT IN BLOW-DOWN WATER	kB/hr	
31	TOTAL HEAT OUTPUT $\frac{(\text{Item } 26 \times \text{Item } 20) + (\text{Item } 27 \times \text{Item } 21) + \text{Item } 30}{1000}$	kB/hr	

FLUE GAS ANAL. (BOILER) (ECON) (AIR HTR) OUTLET

32	CO_2	% VOL	14.4
33	O_2	% VOL	3.3
34	CO	% VOL	0.04
35	N_2 (BY DIFFERENCE)	% VOL	82.26
36	EXCESS AIR	%	

FUEL DATA

	COAL AS FIRED PROX. ANALYSIS	% wt
37	MOISTURE	5.4
38	VOL MATTER	
39	FIXED CARBON	
40	ASH	
	TOTAL	
41	Btu per lb AS FIRED	11452
42	ASH SOFT TEMP.* ASTM METHOD	

	COAL OR OIL AS FIRED ULTIMATE ANALYSIS	
43	CARBON	67.27
44	HYDROGEN	4.29
45	OXYGEN	
46	NITROGEN	
47	SULPHUR	0.77
40	ASH	15.87
37	MOISTURE	
	TOTAL	

	COAL PULVERIZATION	
48	GRINDABILITY INDEX*	-
49	FINENESS % THRU 50 M*	
50	FINENESS % THRU 200 M*	

64	INPUT-OUTPUT EFFICIENCY OF UNIT %	$\frac{\text{ITEM } 31 \times 100}{\text{ITEM } 29}$

	OIL	
51	FLASH POINT F*	
52	Sp. Gravity Deg. API*	
53	VISCOSITY AT SSU* BURNER SSF	
44	TOTAL HYDROGEN % wt	
41	Btu per lb	

	GAS	% VOL
54	CO	
55	CH_4 METHANE	
56	C_2H_2 ACETYLENE	
57	C_2H_4 ETHYLENE	
58	C_2H_6 ETHANE	
59	H_2S	
60	CO_2	
61	H_2 HYDROGEN	
	TOTAL	
	TOTAL HYDROGEN % wt	
62	DENSITY 68 F ATM. PRESS.	
63	Btu PER CU FT	
41	Btu PER LB	

	HEAT LOSS EFFICIENCY	Btu/lb A. F. FUEL	% of A. F. FUEL
65	HEAT LOSS DUE TO DRY GAS		6.90
66	HEAT LOSS DUE TO MOISTURE IN FUEL		0.55
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2		3.95
68	HEAT LOSS DUE TO COMBUST. IN REFUSE		1.26
69	HEAT LOSS DUE TO RADIATION		0.002
70	UNMEASURED LOSSES		0.5
71	TOTAL		13.16
72	EFFICIENCY = (100 – Item 71)		86.84

* Not Required for Efficiency Testing

† For Point of Measurement See Par. 7.2.8.1-PTC 4.1-1964

TABLE E-2

PTC 4.1-b (1964)

ASME TEST FORM

CALCULATION SHEET

FOR ABBREVIATED EFFICIENCY TEST

Revised September, 1965

OWNER OF PLANT TVA TEST NO. 1A BOILER NO. 6 DATE 4-18-72

30 HEAT OUTPUT IN BOILER BLOW-DOWN WATER = LB OF WATER BLOW-DOWN PER HR × $\left[\frac{\overset{\text{ITEM 15}}{\dots\dots} - \overset{\text{ITEM 17}}{\dots\dots}}{1000}\right]$ = ... kB/hr

24 *If impractical to weigh refuse, this item can be estimated as follows*

DRY REFUSE PER LB OF AS FIRED FUEL = $\frac{\text{\% ASH IN AS FIRED COAL}}{100 - \text{\% COMB. IN REFUSE SAMPLE}}$

CARBON BURNED PER LB AS FIRED FUEL = $\frac{\overset{\text{ITEM 43}}{67.27}}{100} - \left[\frac{\overset{\text{ITEM 22}}{0.1587} \times \overset{\text{ITEM 23}}{912.1}}{14{,}500}\right] = 0.66$

NOTE: IF FLUE DUST & ASH PIT REFUSE DIFFER MATERIALLY IN COMBUSTIBLE CONTENT, THEY SHOULD BE ESTIMATED SEPARATELY. SEE SECTION 7, COMPUTATIONS.

25 DRY GAS PER LB AS FIRED FUEL BURNED = $\frac{11CO_2 + 8O_2 + 7(N_2 + CO)}{3(CO_2 + CO)}$ × (LB CARBON BURNED PER LB AS FIRED FUEL + $\frac{3}{8}$ S)

$$= \frac{11 \times \overset{\text{ITEM 32}}{14.4} + 8 \times \overset{\text{ITEM 33}}{3.3} + 7\left(\overset{\text{ITEM 35}}{82.26} + \overset{\text{ITEM 34}}{0.04}\right)}{3 \times \left(\overset{\text{ITEM 32}}{14.4} + \overset{\text{ITEM 34}}{0.04}\right)} \times \left[\overset{\text{ITEM 24}}{0.66} + \frac{\overset{\text{ITEM 47}}{0.77}}{267}\right] = 11.6$$

36 EXCESS AIR† = $100 \times \frac{O_2 - \frac{CO}{2}}{.2682N_2 - (O_2 - \frac{CO}{2})} = 100 \times \frac{\text{ITEM 33} - \frac{\text{ITEM 34}}{2}}{.2682\,(\text{ITEM 35}) - (\text{ITEM 33} - \frac{\text{ITEM 34}}{2})}$ = ...

	HEAT LOSS EFFICIENCY	Btu/lb AS FIRED FUEL	$\frac{\text{LOSS}}{\text{HHV}} \times 100 =$	LOSS %
65	HEAT LOSS DUE TO DRY GAS = LB DRY GAS PER LB AS FIRED FUEL × C_p × ($t_{lvg} - t_{air}$) = $\overset{\text{ITEM 25}}{11.6} \times 0.24\ \overset{\text{(ITEM 13)} - \text{(ITEM 11)}}{372 - 88}$ = 790	790	$\frac{65}{41} \times 100 =$	6.90
66	HEAT LOSS DUE TO MOISTURE IN FUEL = LB H_2O PER LB AS FIRED FUEL × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = $\frac{\overset{5.4}{\text{ITEM 37}}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] = 63.3 1227.9 56	63.3	$\frac{66}{41} \times 100 =$	0.55
67	HEAT LOSS DUE TO H_2O FROM COMB. OF H_2 = $9H_2$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T GAS LVG) − (ENTHALPY OF LIQUID AT T AIR)] = 9 × $\frac{\overset{4.29}{\text{ITEM 44}}}{100}$ × [(ENTHALPY OF VAPOR AT 1 PSIA & T ITEM 13) − (ENTHALPY OF LIQUID AT T ITEM 11)] = 452.5 1227.9 56	452.5	$\frac{67}{41} \times 100 =$	3.95
68	HEAT LOSS DUE TO COMBUSTIBLE IN REFUSE = $\overset{\text{ITEM 22}}{0.1587} \times \overset{\text{ITEM 23}}{912.1}$ = 144.8	144.8	$\frac{68}{41} \times 100 =$	1.26
69	HEAT LOSS DUE TO RADIATION* = $\frac{\text{TOTAL BTU RADIATION LOSS PER HR}}{\text{LB AS FIRED FUEL} - \text{ITEM 28}}$	0.2	$\frac{69}{41} \times 100 =$	0.002
70	UNMEASURED LOSSES **	......	$\frac{70}{41} \times 100 =$	0.5
71	TOTAL	......	......	13.16
72	EFFICIENCY = (100 − ITEM 71)	......	......	86.84

† For rigorous determination of excess air see Appendix 9.2 – PTC 4.1-1964

* If losses are not measured, use ABMA Standard Radiation Loss Chart, Fig. 8, PTC 4.1-1964

** Unmeasured losses listed in PTC 4.1 but not tabulated above may by provided for by assigning a mutually agreed upon value for Item 70.

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changes in coal quality and accurate 0_2 and CO measurements duplicating the initial test run, boiler efficiency should also be about the same, provided that there is no change in exit gas temperature. An increase in exit gas temperature (+10 to 20°F) with no change in 0_2, CO or stack opacity would signal slagging of the furnace walls, or fouling in the superheater, reheater, economizer or air heater sections. Steps should then be taken to clean up the boiler surfaces by thorough and perhaps prolonged operation of the slag and sootblowers, by dropping load severely to shock and deslag furnace surfaces, or by taking the boiler out of service for clean up.

An increase in stack opacity at the same 0_2 level could result from a change in coal quality. Under these circumstances, however, CO values for equivalent 0_2 readings, should also be higher. This occurrence would require an increase in excess air so that maximum CO levels (200 ppm) are re-established to clean up the stack. Obviously, then it would not be possible to repeat the optimum low NO combustion mode firing this type of coal.

Most utility boilers maintain hourly logs of pertinent boiler data which include 0_2 and boiler exit gas temperature measurements. Periodically, say on a frequency of once per week or bi-weekly, CO measurements and stack opacity observations could be made at optimum low NO_x combustion conditions, as discussed previously, to document and ascertain that boiler efficiency standards are being maintained. Boiler log data over a period of time then will show if there is any drift in operating conditions leading to lower efficiencies and pinpoint the need for preventative maintenance to restore the boiler to full capabilities.

APPENDIX F

CONVERSION FACTORS

SI Units to Metric or English Units

To Obtain	From	Multiply By
g/Mcal	ng/J	0.004186
10^6 Btu	GJ	0.948
MBH/ft^2	$GJ \cdot hr^{-1} \cdot m^{-2}$	0.08806
MBH/ft^3	$GJ \cdot hr^{-1} \cdot m^{-3}$	0.02684
Btu	gm cal	3.9685×10^{-3}
10^3 lb/hr* or MBH	GJ/hr	0.948
10^3 lb/hr* or MBH	MW	3.413
lb/MBtu	ng/J	0.00233
ft	m	3.281
in	cm	0.3937
ft^2	m^2	10.764
ft^3	m^3	35.314
lb	Kg	2.205
Fahrenheit	Celsius	$t_F = 9/5\ (t_c)+32$
	Kelvin	$t_F = 1.8K - 460$
psig	Pa	$P_{psig} = (P_{pa})(1.450x10^{-4})-14.7$
psia	Pa	$P_{psia} = (P_{pa})(1.45x10^{-4})$
iwg (39.2^{o}F)	PA	$P_{iwg} = (P_{pa})(4.014x10-3)$

To Obtain ppm at 3% O_2 of	Multiply Concentration in ng/J by
Natural Gas Fuel	
CO	3.23
HC	5.65
NO or NO_x	1.96
SO_2 or SO_x	1.41
Oil Fuel	
CO	2.93
HC	5.13
NO or NO_x	1.78
	1.78
SO_2 or SO_x	1.28
Coal Fuel	
CO	2.69
HC	4.69
NO or NO_x	1.71
SO_2 or SO_x	1.18

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*lb/hr of equivalent saturated steam

APPENDIX F

CONVERSION FACTORS

English and Metric Units to SI Units

To Obtain	From	Multiply By
ng/J	lb/MBtu	430
ng/J	g/MCal	239
$GJ\cdot hr^{-1}\cdot m^{-2}$	MBH/ft^2	11.356
$GJ\cdot hr^{-1}\cdot m^{-3}$	MBH/ft^3	37.257
GJ/hr	10^3 lb/hr* or 10^6 Btu/hr	1.055
MW	10^3 lb/hr* or MBH to MW	0.293
m	ft	0.3048
cm	in	2.54
m^2	ft^2	0.0929
m^3	ft^3	0.02832
kg	lb	0.4536
Celsius	Fahrenheit	$t_c = 5/9\ (t_F - 32)$
Kelvin		$t_K = 5/9\ (t_F - 32) + 273$
Pa	psig	$P_{pa} = (P_{psig} + 14.7)(6.89x10^3)$
Pa	psig	$P_{pa} = (P_{psia})\ (6.895x10^3)$
Pa	iwg (39.2°F)	$P_{pa} = (P_{iwg})(249.1)$

*lb/hr of equivalent saturated steam

To Obtain ng/J of	Multiply Concentration in ppm at 3% O_2 by
Natural Gas Fuel	
CO	0.310
HC	0.177
NO or NO_x (as equivalent NO_2)	0.510
SO_2 or SO_x	0.709
Oil Fuel	
CO	0.341
HC	0.195
NO or NO_x (as equivalent NO_2)	0.561
SO_2 or SO_x	0.780
Coal Fuel	
CO	0.372
HC	0.213
NO or NO_x (as equivalent NO_2)	0.584
SO_2 or SO_x	0.850

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